A Framework for Integrated Analysis of Distributed Energy Resources: Guide for States

Authors:

Natalie Mims Frick and Lisa C. Schwartz, Berkeley Lab

Alyse M. Taylor-Anyikire,[1] U.S. Department of Energy

[1]Electric vehicle sections

Energy Analysis and Environmental Impacts Division
Lawrence Berkeley National Laboratory

Electricity Markets and Policy Group

November 2018

This work was supported by the U.S. Department of Energy's Office of Energy Policy and Systems Analysis under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

A Framework for Integrated Analysis of Distributed Energy Resources: Guide for States

Prepared for the
Office of Energy Policy and Systems Analysis
U.S. Department of Energy

Natalie Mims Frick
Lisa Schwartz
Alyse M. Taylor-Anyikire[1]
[1] Electric vehicle sections

Ernest Orlando Lawrence Berkeley National Laboratory
1 Cyclotron Road, MS 90R4000
Berkeley, CA 94720-8136

November 2018

The work described in this study was funded by the U.S. Department of Energy's Office of Energy Policy and Systems Analysis under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

Acknowledgements

The work described in this study was funded by the U.S. Department of Energy's Office of Energy Policy and Systems Analysis under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

The authors thank Carla Frisch, Erin Boyd, John Agan and Alyse Taylor-Anyikire, U.S. Department of Energy, for their support of our work, and the following reviewers: Gary Brinkworth, Nick Dreher, Tom Eckman, Greg Ehrendreich, Rachel Gold, Nathaniel Horner, Fredrich (Fritz) Kahrl, Meegan Kelly, Lorenzo Kristov, Damon Lane, Jay Lucas, Mark Martinez, Dave Parsons, Steve Schiller, Tom Stanton, Greg Wikler and Tim Woolf. The authors also thank Tom Eckman and Chuck Goldman for reviewing our draft ACEEE Summer Study paper on the framework discussed in this report.

A Berkeley Lab Technical Advisory Group provided guidance on the overall framework discussed in this report:

- Brendon Baatz, Gabel Associates
- Jamie Barber, Georgia Public Service Commission
- Gary Brinkworth, Tennessee Valley Authority
- Jessica Burdette, Minnesota Department of Commerce
- Danielle Byrnett, National Association of Regulatory Utility Commissioners
- Paul De Martini, Newport Consulting
- Nick Dreher, Midwest Energy Efficiency Alliance
- Tom Eckman, consultant
- Rachel Gold, American Council for an Energy Efficient Economy
- Howard Geller, Southwest Energy Efficiency Project
- Josh Gould, Consolidated Edison
- Fredrich (Fritz) Kahrl, E3
- Meegan Kelly, ICF
- Lorenzo Kristov, consultant
- Damon Lane, VEIC
- Jay Lucas, North Carolina Utilities Commission
- Mark S. Martinez, Southern California Edison
- John Ollis, Northwest Power and Conservation Council
- David Parsons, Hawaii Public Utilities Commission
- Jennie Potter, Hawaii Public Utilities Commission
- Steve Schiller, Berkeley Lab
- Rodney Sobin, National Association of State Energy Officials
- Tom Stanton, National Regulatory Research Institute
- Greg Wikler, Navigant
- Tim Woolf, Synapse Energy Economics

Table of Contents

Acronyms and Abbreviations

CHP	Combined heat and power
CPUC	California Public Utilities Commission
CVR	Conservation voltage reduction
DER	Distributed energy resource
DG	Distributed generation
DSM	Demand-side management
DSP	Distribution system planning
DOE	U.S. Department of Energy
DR	Demand response
EE	Energy efficiency
EV	Electric vehicle
IRP	Integrated resource planning
IOU	Investor-owned utility
ISO	Independent system operator
ISO-NE	ISO-New England
MISO	Midcontinent Independent System Operator
NWA	Non-wires alternatives
PJM	Pennsylvania, Jersey, Maryland
PV	Photovoltaic (solar)
RTO	Regional transmission operator
SMUD	Sacramento Municipal Utility District
TAG	Technical advisory group
TRM	Technical reference manual

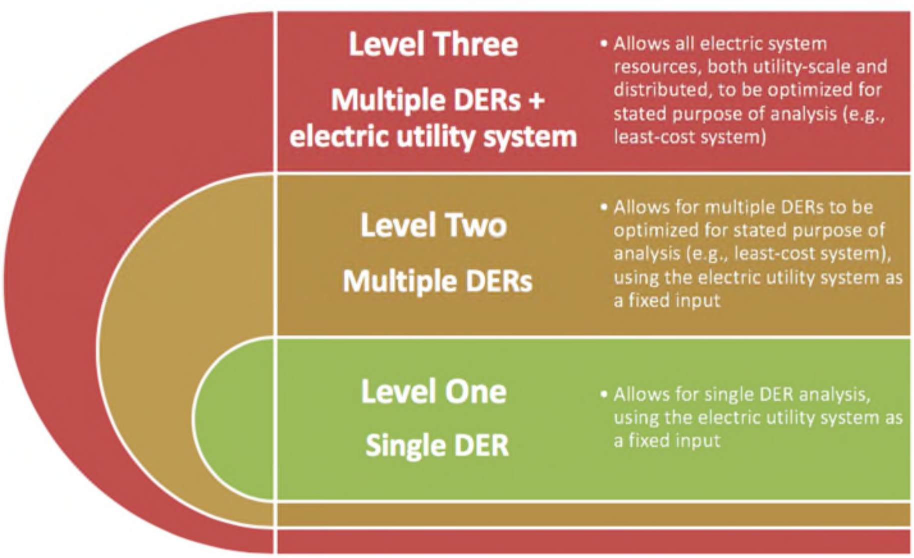
Executive Summary

Electric utilities have been planning for and investing in energy efficiency and demand response for more than three decades. Due to declining costs and other factors, utility planning for and investment in these resources now includes distributed solar photovoltaic systems, multiple storage options, and electric vehicle infrastructure. This wide range of DERs represents both opportunities and challenges for utility planners as they work to include the benefits and costs of DERs. This guide addresses those opportunities and challenges.

Electric utility planning[1] for DERs — limited in this report to demand-side management planning, distribution system planning and resource planning — has struggled to keep up with changes in DER costs and functionality. Few planning efforts have accounted for how multiple types of DERs interact with one another to affect energy savings or generation estimates, or forecasts of electricity system impacts. New, more integrated approaches to considering DER options are emerging and have the potential to identify a lower-cost resource mix, improve reliability and reduce air pollution emissions.

This guide provides a framework for integrated analysis of five types of DERs: energy efficiency, demand response, distributed generation (using combined heat and power and solar photovoltaic systems as examples), distributed storage, and electric vehicles. Figure ES-1 shows the three levels of the framework.

Figure ES-1. Framework for integrated analysis of DERs



All levels incorporate temporal analysis and can incorporate locational values.

[1] Hereafter, we use the term *utility system planning* to collectively refer to demand-side management planning, distribution planning and resource planning.

Berkeley Lab created this guide for state policymakers, public utility commissions and state energy offices that seek an informed perspective on how to begin or advance integrated analysis of DERs, specifically to understand the impact of multiple DERs on the electric system. The framework also may be useful for other stakeholders including utilities, consumer representatives, consultants, and DER product and service providers.

Approach

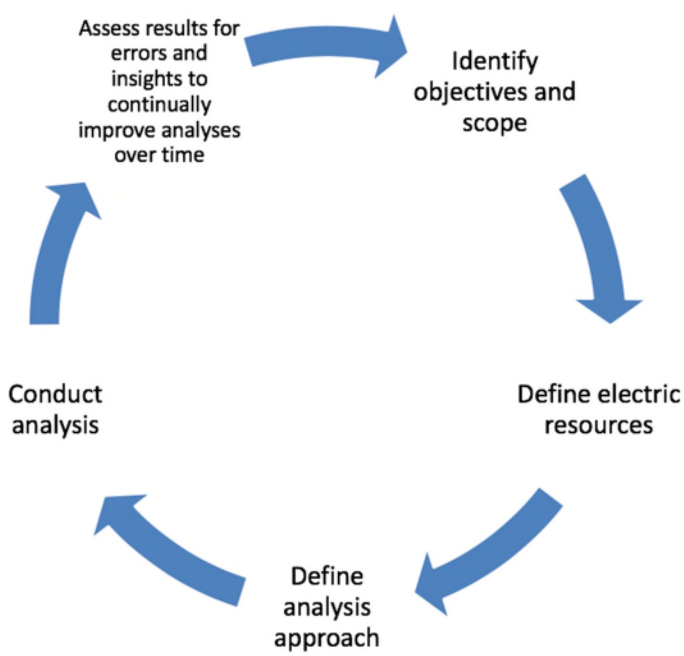
This guide relies on existing research on DERs and utility system planning efforts that consider multiple DERs. Our review of more than 100 reports and utility filings (see References and Appendix A) found that while many utilities and states have included individual DERs in utility system planning, few have undertaken *integrated* analysis of DERs.

In addition to the literature review, we conducted interviews with state public utility commissions, electric utilities, independent system operators, regional planning organizations and DER consultants. All interviewees stated that integrated DER analysis would be useful to inform policies, regulations and programs. The interviewees further noted a lack of available information on the critical assumptions that must be made, or the order in which different DERs should be assessed, to integrate various types of DERs and assess their cumulative impact. Interviewees also pointed out that because few integrated analyses of DERs have been conducted, little information is available on the cost of such an analysis.

Framework for Integrated Analysis of Distributed Energy Resources

The guide provides an approach for determining which of the framework's three levels of analysis may be most appropriate to use. Figure ES-2 provides an overview of the approach, discussed in Chapter 2.

Figure ES-2. General approach for Integrated DER analysis



As Figure ES-1 notes, all levels of the framework should incorporate temporal analysis and can incorporate locational values:

Temporal Analysis. The value of DERs from one time period to another varies based on factors such as generation mix and demand. As used in the guide, temporal analysis applies the estimated cost and value of DERs on a granular time basis within each year, such as by hour, day, month or season.

Locational Analysis. Energy savings or generation output from DERs can be located at different sites on the transmission and distribution grid. The value of DERs is heavily dependent on their location, based on factors such as circuit or substation loading and network configuration. As used in the guide, locational analysis applies the estimated cost and value of DERs, based on the location of the DER with respect to specific circuits, substations or other segments of the grid.

The three levels of the framework are as follows:

Level One. Single DER. Level One analysis quantifies the available savings or generation — energy (kilowatt-hours, kWh) or demand (kilowatts, kW), or both — of one type of DER, assessed individually. In Level One analysis, utility system resources and avoided costs are assumed to be fixed regardless of the amount of DERs installed. For example, in many electricity efficiency potential studies, cost-effectiveness is determined based on the existing or forecasted utility system resources and the associated avoided cost. The avoided resources, and therefore the forecasted avoided cost, do not interact or change based on the level of cost-effective efficiency identified. *Level One allows for analysis — but not necessarily the optimization*[2] *— of a single type of DER.*

Level Two. Multiple DERs. Level Two analysis quantifies the available savings or generation — energy (kWh) or demand (kW), or both — of two or more types of DERs and considers the interactions between them. As with Level One, the utility system resources and avoided costs are assumed to be fixed regardless of the amount of DERs installed. For example, a Level Two analysis could investigate if *simultaneous* installation of distributed solar and storage resources increases or decreases implementation costs and benefits of the DERs. However, as is the case with Level One analysis, Level Two assumes that the combined impact of the resources on the utility system would not alter the resources, and therefore the forecast of avoided costs. *Level Two analysis allows for optimization among multiple DERs, but without respect to their interaction with the electric utility system.*

Level Three. Multiple DERs + Electric Utility System. Level Three analysis identifies the optimal mix of resources, and costs of that resource mix, by considering multiple types of DERs, DER combinations and interactions, and their effects on the electric utility system. At this level, the utility system is modeled dynamically in an optimization model. For example, a Level Three analysis could consider demand

[2] The stated purpose of the analysis will determine the purpose of the optimization, which may be operational (lowest air pollutant emissions) or investment (e.g., least-cost electric system). Level One analysis will indicate the amount of that DER that will be cost-effective given defined avoided cost values, but not the optimal amount of that DER with respect to other possible resources.

response, solar, electric vehicles, energy efficiency and natural gas combustion turbines as resources available to the utility system. The optimization model could consider varying levels of resources, development schedules, and resource locations to create an optimized resource mix solving for the stated purpose (e.g., lowest cost, most reliable electric system). *Level Three analysis allows all electric system resources and costs, both utility-scale and distributed, to be optimized.*

Table ES-1 summarizes the key components of the three framework levels.

Table ES-1. Key components of each level of the analysis framework

	Level 1	Level 2	Level 3
No. of DERs	One	Two or more	
Level of DER integration	Limited, if any	Integrated analysis considering multiple DERs' impact on each other	Integrated analysis considering multiple DERs' impact on all electric utility system resources
Electric utility system interaction	Avoided costs are assumed to be a fixed value.[3]	Avoided costs are assumed to be a fixed value and on the same time scale as *combinations of DERs* being considered.	Avoided costs are dynamically determined.[4]
Analysis outcome*	• Quantification of available savings or generation — energy (kWh) and/or demand (kW) (depending on the DER type) • Quantification of kWh or kW savings or generation that is economic		Identification of the optimal mix of resources, and the cost of that resource mix, that meets the stated purpose of the analysis
Temporal analysis	• Hourly, daily, monthly or seasonal kWh or kW savings or generation may be used in the analysis. • Hourly, daily, monthly or seasonal avoided costs may be used in the analysis.		• Hourly kWh and kW savings or generation • Hourly avoided costs
Locational analysis	• kWh and kW savings or generation may be identified at a specific circuit or substation. • A variety of locational values may be incorporated in the analysis (e.g., avoided costs including distribution capacity infrastructure, transmission capital, generation capacity, energy).[5]		
Benefit	Level One analysis allows for a simplified DER analysis.	Level Two allows for a simplified integrated DER analysis that considers the interactive effects of two or more DERs.	Level Three analysis comprehensively solves for the stated purpose of the analysis from an electric systemwide perspective. Interactive effects, both between DERs and between DERs and the electric utility system, are considered.
Challenges	Exclusion of the ability of DERs to change the optimal portfolio produces results that can over- or underestimate the quantity of DER savings or generation that are optimal on the system.		Increased cost and data requirements are needed to create robust results and resources.

*The purpose of the integrated DER analysis will determine the energy, demand and economic outputs.

---

[3] At this level, the utility system resources and avoided costs are assumed to be fixed regardless of the amount of DERs installed. For example, in many energy efficiency potential studies, cost-effectiveness is determined based on the existing or forecasted utility system resources and avoided cost. The resources and avoided cost do not interact or change based on the level of cost-effective efficiency identified. This methodology assumes that the development of all cost-effective DER potential identified would not materially alter the timing, amount and type of resources used to establish the avoided cost.

[4] See text box on page 14 for more explanation.

[5] See ICF (2018) for more detail.

Several of the illustrative case studies in this guide of integrated DER analysis are examples of energy efficiency and demand response analyzed together in demand-side management planning. Case studies on analysis of DERs in distribution planning fall into several topical categories: distribution system or DER plans, hosting capacity analysis, locational net benefits analysis and non-wires alternatives. To date, there are few case studies of integrated analysis of DERs in integrated resource plans, even though several states require specific DERs to be included. Often the load forecast in the integrated resource plan is simply altered in size or in shape, or both, by the individual DER's impact.

Finally, the report presents a range of DER potential study costs and concludes with observations and next steps. Observations include that integrated analysis of DERs in utility system planning may identify a least-cost resource mix and DER opportunities that would otherwise be missed when planning these resources in isolation. However, the high fidelity of the requisite data, which may include temporal and locational value, as well as complex modeling required to integrate multiple DERs into electric utility system planning, may be challenging and time-consuming.

Opportunities for publicly available research to advance integrated analysis of DERs include: guidelines for DER benefit-cost analysis; interactive effects of combinations of DERs for demand-side management planning, distribution system planning and resource planning; necessary key assumptions for creation of combinations of DERs for Level Two and Level Three analyses; a clearinghouse of case studies, as examples of integrated DER analysis grow, that makes the information more readily available to states, utilities and stakeholders; and identifying and categorizing key policy drivers to promote integrated DER analysis in electric utility system planning.

1. Introduction

Integrated analysis of the energy and demand impacts of DERs — defined in this report as energy efficiency, demand response, distributed generation (as represented by combined heat and power and solar photovoltaic systems), storage and electric vehicles — is rare. Yet such analysis may identify a least-cost resource mix and DER opportunities that would otherwise be missed when planning these resources in isolation.

This guide relies on existing research on DERs and electric utility system planning efforts that consider multiple DERs, including reviewing more than 100 reports and utility filings (see References and Appendix A). We found that while many utilities and states have included individual DERs in utility system planning, few have undertaken *integrated* analysis of DERs. To aid in addressing this gap, this guide provides a framework that can be used for undertaking integrated analysis to assess the quantity and cost of DERs, as well as the estimated benefits and costs of their adoption on the electric utility system, and to plan for DERs.

Chapter 2 provides the study approach, an overview of the framework, and how to implement the framework, including several framing questions that support selection of the appropriate analysis level.

- What is the purpose of the analysis?
- What perspective is appropriate for economic analysis?
- What data are available to support temporal and locational analysis?

The guide also discusses scoping issues that should be considered, including the time frame for the analysis, the primary audience, and whether the study will assess policy, regulatory, or market mechanisms to encourage adoption of DERs using an integrated approach.

Chapters 3 through 5 discuss each level of the framework. Chapter 3 discusses the framework's first level, focusing on temporal analysis of a single type of DER as a foundational step toward integrated evaluation. Chapter 4 discusses the second level, addressing interactive impacts of two or more types of DERs. Chapter 5 discusses the third level, which analyzes in an optimization model the interactions across multiple DERs and incorporates the electric utility system costs.

Chapter 6 describes examples of integrated analysis of DERs in demand-side management plans, DER plans, distribution system planning and resource planning. Chapter 7 provides examples of the estimated cost of DER potential studies. Chapter 8 offers observations and next steps to promote integrated analysis of DERs.

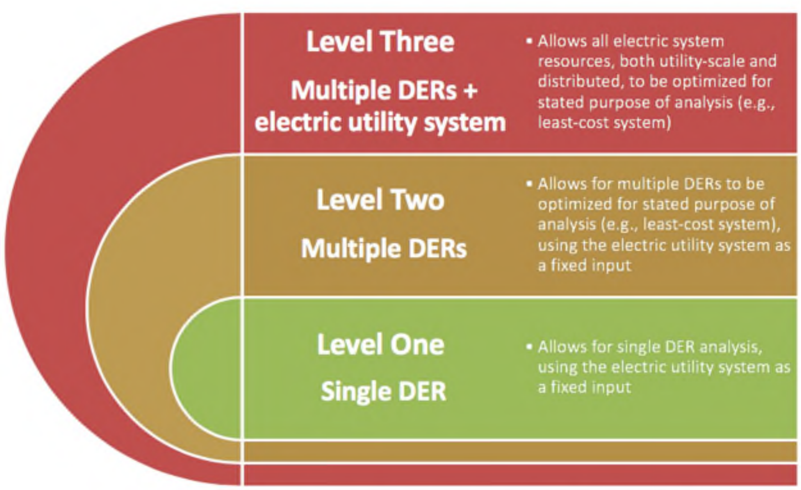
2. Options and Considerations for Integrated Analysis of Distributed Energy Resources

2.1 Framework Overview

Berkeley Lab created this guide for state policymakers, public utility commissions and state energy offices that seek an informed perspective on how to begin or advance integrated analysis of DERs, specifically to understand the impact of multiple DERs on the electric system. The framework also may be useful for other stakeholders including utilities, consumer representatives, consultants, and DER product and service providers.

This guide provides a framework for integrated analysis of five types of DERs: energy efficiency, demand response, distributed generation (using combined heat and power and solar photovoltaic systems as examples), distributed storage, and electric vehicles. The framework provides information about what to consider when modeling DERs for three possible levels of analysis, from simplest to more complex, summarized in Figure 1.[6]

Figure 1. Framework for integrated analysis of DERs



All levels incorporate temporal analysis and can incorporate locational values.

As noted in Figure 1, all levels of the framework should incorporate temporal analysis and can incorporate locational values:

Temporal Analysis. The value of DERs from one time period to another varies based on factors such as generation mix and demand. As used in the guide, temporal analysis applies the estimated cost and value of DERs on a granular time basis within each year, such as by hour, day, month or season.

[6] All of these levels of analysis can include temporal and locational analysis. See “General Approach” (Chapter 3.1) and detailed descriptions of each level of analysis in Chapters 4 through 6.

Locational Analysis. Energy savings or generation output from DERs can be located at different sites on the transmission and distribution grid. The value of DERs is heavily dependent on their location, based on factors such as circuit or substation loading and network configuration. As used in the guide, locational analysis applies the estimated cost and value of DERs, based on the location of the DER with respect to specific circuits, substations or other segments of the grid.

The three levels of the framework are as follows:

Level One. Single DER. Level One analysis quantifies the available savings or generation — energy (kilowatt-hours, kWh) or demand (kilowatts, kW), or both — of one type of DER, assessed individually. In Level One analysis, utility system resources and avoided costs are assumed to be fixed regardless of the amount of DERs installed. For example, in many electricity efficiency potential studies, cost-effectiveness is determined based on the existing or forecasted utility system resources and the associated avoided cost. The avoided resources, and therefore the forecasted avoided cost, do not interact or change based on the level of cost-effective efficiency identified. *Level One allows for analysis — but not necessarily the optimization[7] — of a single type of DER.*

Level Two. Multiple DERs. Level Two analysis quantifies the available savings or generation — energy (kWh) or demand (kW), or both — of two or more types of DERs and considers the interactions between them. As with Level One, the utility system resources and avoided costs are assumed to be fixed regardless of the amount of DERs installed. For example, a Level Two analysis could investigate if *simultaneous* installation of distributed solar and storage resources increases or decreases implementation costs and benefits of the DERs. However, as is the case with Level One analysis, Level Two assumes that the combined impact of the resources on the utility system would not alter the resources, and therefore the forecast of avoided costs. *Level Two analysis allows for optimization among multiple DERs, but without respect to their interaction with the electric utility system.*

Level Three. Multiple DERs + Electric Utility System. Level Three analysis identifies the optimal mix of resources, and costs of that resource mix, by considering multiple types of DERs, DER combinations and interactions, and their effects on the electric utility system. At this level, the utility system is modeled dynamically in an optimization model. For example, a Level Three analysis could consider demand response, solar, electric vehicles, energy efficiency and natural gas combustion turbines as resources available to the utility system. The optimization model could consider varying levels of resources, development schedules, and resource locations to create an optimized resource mix solving for the stated purpose (e.g., lowest cost, most reliable electric system). *Level Three analysis allows all electric system resources and costs, both utility-scale and distributed, to be optimized.*

Table 1 summarizes the key components of the three framework levels.

[7] The stated purpose of the analysis will determine the purpose of the optimization, which may be operational (lowest air pollutant emissions) or investment (e.g., least-cost electric system). Level One analysis will indicate the amount of that DER that will be cost-effective given defined avoided cost values, but not the optimal amount of that DER with respect to other possible resources.

Table 1. Key components of each level of the analysis framework

	Level 1	Level 2	Level 3
No. of DERs	One	Two or more	
Level of DER integration	Limited, if any	Integrated analysis considering multiple DERs' impact on each other	Integrated analysis considering multiple DERs' impact on all electric utility system resources
Electric utility system interaction	Avoided costs are assumed to be a fixed value.[8]	Avoided costs are assumed to be a fixed value and on the same time scale as *combinations of DERs* being considered.	Avoided costs are dynamically determined.[9]
Analysis outcome*	• Quantification of available savings or generation — energy (kWh) and/or demand (kW) (depending on the DER type) • Quantification of kWh or kW savings or generation that is economic		Identification of the optimal mix of resources, and the cost of that resource mix, that meets the stated purpose of the analysis
Temporal analysis	• Hourly, daily, monthly or seasonal kWh or kW savings or generation may be used in the analysis. • Hourly, daily, monthly or seasonal avoided costs may be used in the analysis.		• Hourly kWh and kW savings or generation • Hourly avoided costs
Locational analysis	• kWh and kW savings or generation may be identified at a specific circuit or substation. • A variety of locational values may be incorporated in the analysis (e.g., avoided costs including distribution capacity infrastructure, transmission capital, generation capacity, energy).[10]		
Benefit	Level One analysis allows for a simplified DER analysis.	Level Two allows for a simplified integrated DER analysis that considers the interactive effects of two or more DERs.	Level Three analysis comprehensively solves for the stated purpose of the analysis from an electric systemwide perspective. Interactive effects, both between DERs and between DERs and the electric utility system, are considered.
Challenges	Exclusion of the ability of DERs to change the optimal portfolio produces results that can over- or underestimate the quantity of DER savings or generation that are optimal on the system.		Increased cost and data requirements are needed to create robust results and resources.

*The purpose of the integrated DER analysis will determine the energy, demand and economic outputs.

[8] At this level, the utility system resources and avoided costs are assumed to be fixed regardless of the amount of DERs installed. For example, in many energy efficiency potential studies, cost-effectiveness is determined based on the existing or forecasted utility system resources and avoided cost. The resources and avoided cost do not interact or change based on the level of cost-effective efficiency identified. This methodology assumes that the development of all cost-effective DER potential identified would not materially alter the timing, amount and type of resources used to establish the avoided cost.

[9] See text box on page 14 for more explanation.

[10] See ICF (2018) for more detail.

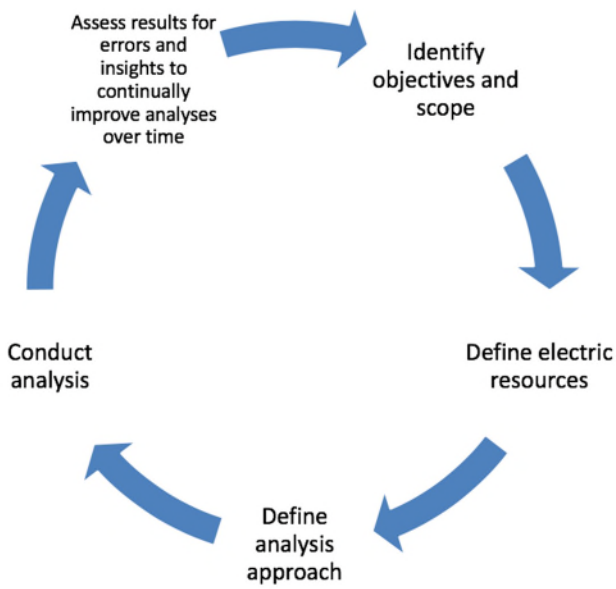
The rest of this chapter describes the general approach to integrated DER analysis, including key questions to consider when conducting any DER analysis. This chapter also discusses minimum data requirements and current modeling approaches. Chapters 3 through 5 address specific issues related to each level of analysis.

2.2 Approach for the Framework

Each level of the framework follows the same general analytical approach, consisting of five basic steps (Figure 2). Thinking through the key questions identified below will aid in deciding which framework level is most appropriate for the analysis. The main decision being made when selecting a framework level is ultimately simplicity versus complexity, which translates into a decision about time, resources and accessibility.

First, clearly identify the objectives and scope. There are a variety of reasons to conduct an analysis of a DER in isolation or in an integrated way. Clearly identifying the objectives of the study and the desired results will provide guidance throughout the analysis as data issues and research challenges arise. *Second, define the electric resources that will be considered in the analysis, the level of detail, and the data needs.* The availability, quality and fidelity of data are likely the most influential factors in determining the study's cost. Publicly available data sources exist for most DERs on the state level, but the data may not have enough fidelity to support a robust temporal or locational analysis for the DER(s). A minimum list of data needs for any analysis level is discussed below. *Third, define the study methodology.* This guide offers three levels of analysis, discussed in Chapters 3 through 5. *Fourth, conduct the analysis; and fifth, assess the results for errors and insights, and continually improve analyses over time.*

Figure 2. Approach for the framework



Key questions to consider when determining the scope and objectives of the study are:

- **What is the purpose of the analysis?** It is important to determine if the study will be used for DER planning, distribution planning, transmission planning, resource planning, or some other purpose.
- **What are the existing policies?** When determining the purpose of the analysis, existing policies may influence the scope of work. For example, are there energy efficiency resource standards, renewable portfolio standards, or other resource requirements that will affect the analysis?
- **What electric resources will be considered?** What DERs will be considered in the analysis? The analyst can use prior planning exercises as a starting point to identify which data are available and which data will be needed.
- **How will the existing electric utility system be considered?** The existing electric utility system should be accurately represented in the analysis. One option is to use the existing electric utility case as a reference or business as usual case. As discussed more in Chapters 3 through 6, the existing electric utility system remains static in levels One and Two, and is an input to the optimization model in Level Three.
- **What perspective is appropriate for economic analysis?** Depending on the identified purpose or legislative or regulatory requirements for analysis, the study could consider DER economics from a variety of perspectives.[11] Examples include the societal perspective (e.g., include public health, economic development or other societal benefits in evaluating the costs and benefits of DERs), consumer perspective (e.g., using retail rates to determine the payback period for one or more DERs), or the electric system perspective (e.g., using system avoided costs for determining cost-effectiveness). To illustrate, if the study's goal is to understand how much solar photovoltaic (PV) and how many electric vehicles (EVs) will be adopted in a certain neighborhood over the next five years, a consumer's perspective may be appropriate. Alternatively, if the goal is to understand the quantity of DERs that can be acquired cost-effectively to defer certain types of distribution system infrastructure investments (e.g., for load relief), it may be appropriate to use the electric system perspective, including locational values.
- **What data are available to support temporal analysis?** While some analyses may use average daily, monthly or even annual values, a robust analysis requires annual hourly data for determining the value of energy savings or generation output, with associated hourly (utility system) avoided costs for utility system perspective analyses. Hourly data requires information on DER load shapes[12] and utility system load shapes. The primary differences between the two methods are the fidelity or granularity of data requirements and the method used to determine peak impacts of the DERs.[13]
- **What data are available to support locational analysis?** Locational values are about the specific site of the DER in the electric system and thus the specific avoided cost value of the resource at

[11] Woolf et al. (2017).

[12] The U.S Energy Information Administration defines a *load shape* as a method of describing peak load demand and the relationship of power supplied to the time of occurrence. https://www.eia.gov/tools/glossary/index.php

[13] For a more in-depth discussion of the temporal value of efficiency, see Mims, Eckman, and Goldman (2017).

the location. The goal or purpose of the analysis will determine if locational values are necessary (e.g., critical in distribution system planning). An approach to calculating the values (Navigant 2016) or a proxy cost may be available.[14] Some states are beginning to require locational analyses of DERs for distribution system planning.[15]

- **Will the study consider DER customer adoption?** In addition to identifying the quantity of DERs that are available, the study could use a customer adoption model to understand how much of an identified resource will be installed. The study approach will vary based on whether the objective is to determine the quantity of DERs available, how many customers will adopt DERs, or both.

2.3 Minimum Data Requirements

The data requirements discussed below are needed for any DER analysis. The temporal and locational resolution becomes more important for accurate integrated analysis. Additional data needs are discussed in Chapters 3 through 5. It should be noted that data requirements become more extensive for Level 3 analysis (Chapter 5), where electric utility system costs are calculated within the model.

- *Electricity demand forecast(s):* An electricity demand forecast for the length of time and the geographic region that the study will cover is necessary to understand the quantity of electricity that DERs might displace. State-level electricity demand forecasts may be publicly available from electric utilities in long-term planning proceedings such as integrated resource plans (IRPs) or from state energy offices or regional planning bodies. If the DER analysis will consider varying levels of electricity demand growth, use of low, medium and high electricity demand forecasts are needed at minimum. The temporal granularity of both the load and avoided cost forecasts should match the granularity of the DER analysis; for example, if the DER analysis is hourly then load and avoided cost forecasts should both also be hourly.
- *Avoided costs:* Energy-[16] and generation-related capacity[17] avoided costs must be considered when determining the economic potential of a single type of DER or integrated, multiple DERs. Energy-related costs should be considered by the time segment (e.g., hourly, by peak and off-peak period) of additional energy supplies needed. Generation, transmission and distribution avoided costs should be expressed as levelized cost by time segment ($/kWh), present value

[14] Until a resource planning optimization process is conducted, the cost of the specific resource or resources that would be avoided by development of DERs is unknown. Therefore, the cost of a resource (or resources) *expected* to be avoided must be used to approximate (to serve as a proxy for) the avoided cost.

[15] For more information on DERs in distribution system planning, see Homer et al. (2017) and Washington Utilities and Transportation Commission (2017b).

[16] For vertically integrated utilities, energy-related avoided costs are typically represented by the levelized cost of energy from a new power plant, including fuel, capital, fixed operation, maintenance and periodic capital replacement costs. In centrally organized wholesale electricity markets (e.g., MISO, PJM, ISO-NE), avoided energy costs are typically represented by the forecast of future market prices for energy, capacity and associated ancillary services (e.g., reserves).

[17] Avoided generation costs include capital, fixed operation, maintenance and periodic capital replacement costs. Depending on the location and avoided cost methodology, this value may be determined by a proxy generating unit or the marginal capacity value of the system.

cost by time segment ($/kWh), or present value cost by time segment ($/kW-yr). Other avoided costs, including ancillary services,[18] air pollutant emissions costs,[19] renewable resource cost,[20] risk mitigation cost,[21] and demand reduction induced price effect[22] may also be considered.[23]

- *DER output or load shapes and expected resource life:* It is necessary to know when, and over how many years, the DERs being considered in the study are saving or generating energy, including the DER's expected lifetime. Depending on the DER type, a variety of assumptions may need to be developed to determine the DER load or capacity shape (e.g., for storage, the charge and discharge rates, size and type of storage). It is important to use DER load or capacity shape data that are at the same temporal granularity as the avoided cost data that are available.[24]
- *Development or acquisition cost for DERs:* Assumptions about the cost to develop or acquire DERs are necessary to evaluate them as resource options (e.g., for combined heat and power [CHP], the study will need to determine which sectors to include to determine CHP potential, typical technology costs, and performance characteristics for these sectors, and if the potential is based on thermal load, electrical load or optimizing between them).
- *Lead times:* When evaluating electric resources over a period of time, it is necessary to know how long it takes for the resource to become available to the electric system.
- *Uncertainty:* Point estimates can be used for these data, but ranges are more useful — e.g., ranges of DER and avoided costs. Such ranges can be used in scenario, sensitivity and Monte Carlo-type analyses.

2.4 Tools to Evaluate Distributed Energy Resources

Numerous tools are available to evaluate DERs for a variety of objectives. Many rely on proprietary data or software, and each platform has its strengths and weaknesses. A detailed review of the tools or approaches to evaluating DERs is beyond the scope of this paper.

---

[18] Ancillary services are the specialty services and functions provided by the electric grid that facilitate and support the continuous flow of electricity so that supply will continually meet demand. The term *ancillary services* refers to a variety of operations beyond generation and transmission that are required to maintain grid stability and security. Avoided costs from ancillary services are from the reduced requirements for frequency control and spinning and operating reserves, if not captured in generation capacity cost ($/kW-yr).

[19] For example, levelized cost of carbon dioxide (CO_2) emissions by time segment ($/kWh) if applicable (e.g., Regional Greenhouse Gas Initiative [RGGI], California CO_2 cap and trade) or compliance costs.

[20] Reduced development obligation by time segment ($/kWh), applicable where state Renewable Portfolio Standards (RPS) obligations exist.

[21] Value of reducing exposure to fuel price, technology change and other stochastic variation in planning assumptions ($/kWh).

[22] Value by time segment of reductions in wholesale market prices for energy, capacity and cross-fuel from reduced demand for energy or capacity ($/kWh or $/kW).[22]

[23] However, monetization of these and other societal and utility system benefits for which a potential study may be optimized are not a focus of this framework. For a more detailed discussion of avoided costs see Mims, Eckman, and Goldman (2017).

[24] For example, for energy efficiency, see Mims, Eckman, and Goldman (2017).

Level One analysis may only require use of a spreadsheet. Level Two likely requires a more sophisticated model to consider the interaction between DERs. For both Level One and Level Two, the existing electric utility system should be modeled in a production cost model and capacity expansion model if possible. However, those analyses would likely occur *outside* of the Level One or Level Two analyses, and would be a data input to the analyses. Level Three requires a capacity expansion model to consider bulk electric resources and DERs and a production cost model to help with incorporating the change in avoided cost based on different resource mixes. For more information on capacity expansion models and production cost models, see Boyd (2017) and Appendix A.

Tools to Evaluate DERs

Production cost models and capacity expansion models can both simulate the economic dispatch of an existing power system. Depending on their sophistication, both model types can be used to estimate individual generation unit hourly (and in some cases subhourly) output and cost, as well as the production costs for an existing power system, including market equilibrium prices, transmission congestion prices and other outputs (e.g. air emissions).

Capacity expansion models differ from production costing models because they also include data on the characteristics of new resources and use reliability criteria and economic decision rules (sometimes referred to as "optimization logic") to determine the type, amount and schedule for new resource development required to meet the forecasted future need for energy and capacity.

Several recent reports summarize the ability of existing tools or modeling approaches to address DERs in IRP and distribution system planning. The Electric Power Research Institute (EPRI) published a report exploring opportunities for improving long-term planning models in four key areas: (1) temporal resolution, (2) spatial resolution, (3) representation of end-use details, and (4) representation of uncertainty.[25] A report by Pacific Northwest National Laboratory and National Renewable Energy Laboratory summarizes major types of analysis for electric distribution systems, their applications, and relative maturity levels, focusing on the analysis required for increasing levels of DERs.[26]

Berkeley Lab recently conducted a review of two capacity expansion models for the Minnesota Public Utilities Commission. In reviewing the EnCompass and Aurora capacity expansion models as requested by the Minnesota Public Utilities Commission staff, Berkeley Lab considered their capability to: (1) model demand response, energy efficiency, distributed generation and storage resources; (2) model compliance with renewable and technology-specific standards; (3) account for reliability, risk and uncertainty; (4) model emissions and societal externality costs; (5) evaluate system dispatch and commitment; and (6) model electric systems in an ISO environment.[27] Unlike for generating resources, the databases provided by the model vendors do not include "default" characteristics for DERs. All of

[25] EPRI (2017a).

[26] For more detail on modeling DERs, see Tang et al. (2017), IREC Editors (2017), Mills et al. (2016), and Frew et al. (2017). For more information on modeling the locational value of energy efficiency for distribution planning, see Mihlmester and Fine (2016).

[27] See Eckman and Schwartz (2018).

these DERs can be modeled as options in both Aurora and EnCompass, but users must define the specific DER characteristics such as cost, quantity, lead times and load shapes. Though other capacity expansion models were not reviewed in the Minnesota study, it is likely that other currently available commercial models will require user-defined DER characteristics for their inputs.

3. Level One: Single Distributed Energy Resource

Level One identifies the quantity of (energy savings or generation output) or opportunity for one type of DER based on a fixed electric utility system (e.g., specific type, amount and timing of electric utility system resources). There is limited, if any, optimization conducted at this level.

As with each level of the framework, the stated purpose of the analysis will guide the modeling approach. For example, if the stated purpose is preliminary analysis of DER feasibility, the outcome may be a relatively simple DER potential study. Alternatively, if the goal is identification of options to defer distribution upgrades or expansion, the analysis will need to include locational values and will require a more sophisticated and detailed analysis. The "Minimum Data Requirements" discussion in Chapter 3 provides guidance for Level One analysis. Electricity demand forecasts, proxy avoided costs, and load or generation shape data will be used to calculate the value of DERs.[28] These data, in the form of annual hourly load profiles, provide detail about when the DER is generating or saving energy for every hour of the year.

If the Level 1 analysis determines economic potential, the study may include temporal analysis by using hourly, or peak and off-peak, avoided costs to determine the value of the savings or generation output. At a minimum, the avoided cost data needed for the analysis must permit a high-level temporal analysis. In its simplest form, this analysis uses daily or seasonal load shape data, or both, to allocate energy savings or generation output into peak periods and off-peak periods. Peak impacts are derived using coincidence factors.[29] Avoided costs for the comparable daily or seasonal peak and off-peak periods are then used to determine the value of savings or generation output for those time periods.[30]

For a more detailed DER analysis, higher fidelity temporal values (e.g., hourly avoided costs for energy and capacity) may be used in conjunction with hourly load shapes or generation output profiles, or

---

[28] It is valuable to provide annual hourly load profiles in DER potential studies to increase transparency.

[29] A *coincidence factor* is the ratio of the simultaneous maximum demand of two or more loads within a specified period to the sum of their individual maximum demand within the same period. The ratio may be expressed as a numerical value or as a percentage. The coincidence factor is the reciprocal of the diversity factor and is always less than or equal to one.

[30] To properly characterize the full value to the utility system of some DERs, such as battery storage or some forms of DR, highly granular (hourly or subhourly) data are required. For example, if DR is to be used to integrate variable energy resources such as wind and solar, the potential to deploy DR and the value of doing so requires subhourly data. As another example, because storage resources can be used to provide ancillary services such as frequency control, their rate of discharging and charging needs to be characterized in terms of seconds, not hours or days.

both. Use of this more granular data produces more precise results, avoiding the potential for either over- or understating the value of DERs.

DER potential studies to date, including those that focus on a single type of DER, typically have not included locational data. However, as requirements for distribution system planning are beginning to include consideration of DERs, future Level One type analyses may begin to include locational value.[31] Potential studies that determine achievable potential[32] will need to make assumptions about customer adoption, both with and without policy intervention (e.g., state or federal incentives, utility programs).[33]

The benefit of a Level One DER potential study is that it provides the first step toward a better understanding of how DERs can be used or will influence the electric utility system costs. More broadly, a DER potential study can be a tool that helps inform a larger analysis (e.g., IRP or distribution system plan), guide decisions about the need for more in-depth DER analysis, identify a DER goal (e.g., energy efficiency or demand response goals for a DSM plan), or identify the need for market or policy intervention.

The primary limitation of a Level One DER potential study is that it only evaluates a single type of DER and does not consider how DERs interact with each other or with the electric utility system. This simplifying assumption (that one DER's potential does not impact the potential of other DERs, nor alter the electric utility system sufficiently to impact avoided costs) produces results that can be misleading and are usable only at higher levels or for specific limited purposes.[34] The second level of analysis in this framework is intended to address this limitation.

4. Level Two: Multiple Distributed Energy Resources

Level Two of the framework evaluates two or more types of DERs, including consideration of interactions between them, compared to a baseline electric system, but still does not account for the interaction of these DERs with the bulk power system. A Level Two analysis can build on the analysis conducted in Level One or use existing DER potential studies if they offer the appropriate level of granularity.

Interactions between DERs can be modeled with two basic approaches: (1) manually creating a combination of DERs to provide a set mix of DERs with specific characteristics as a model input, or (2) allowing a model to choose from all DERs provided to it in order to optimize use of defined criteria and DER characteristics. Most models available today will need manually created combinations, either

---

[31] For more information on state distribution planning efforts see Homer et al. (2017); Cooke, Homer, and Schwartz (2018); and Black and Veatch (2017).

[32] For an explanation of technical, economic and achievable potential of energy efficiency, see DOE's Energy Efficiency Potential Studies Catalog at https://www.energy.gov/eere/slsc/energy-efficiency-potential-studies-catalog.

[33] For more information on DER forecasting see Gagnon et al. (2018), Mills et al. (2016), and CPUC (2017).

[34] For more information on the limitations of potential studies, see Kramer and Reed (2012).

to reduce run time or to ensure logical DER combinations are created, because it may be necessary to run multiple iterations of a model if it is allowed to choose DER combinations. For example, the first iteration of the analysis would estimate the potential assuming that energy efficiency resources are applied first, followed by the adoption of demand response measures. The second iteration would then estimate the combined potential and cost of these two DERs, assuming the reverse order of application. The number of iterations required to complete an analysis is determined by the number of unique combinations and order of application of the DERs under consideration.

As with Level One, the Level Two analysis assumes that electric utility system resource mix and avoided costs remain unchanged by the amount of DERs that are added to the system. Also similar to Level One, the electricity demand forecast, proxy avoided costs, and the load or generation shape data are used in calculating the utility system value of the DERs.

When developing DER combinations to test, users can use three basic economic optimization perspectives of:

1. combinations designed to maximize societal benefit,
2. combinations designed to minimize utility system cost, and
3. combinations designed to maximize customer bill savings.

As an example, the combinations resulting from optimization from a participant perspective would maximize retail bill savings, a utility perspective would maximize impacts during periods of high demand or distribution system congestion, and the societal point of view would maximize reductions in pollutant emissions from a societal point of view. Using distributed solar and storage as example DERs, depending on the perspective, the solar may be oriented in different directions, and the storage may be discharged at different times of the day. Both of these decisions will create different load shapes, which will subsequently result in different values for various combinations.

Beyond the data discussed under "Minimum Data Requirements" in Chapter 3, additional information or assumptions will be necessary to create the Level Two DER combinations. The information or assumptions will not necessarily be the same for each DER. For example, to create various combinations of energy efficiency, demand response, and electric vehicles, the analyst must determine the timing and quantity of energy efficiency savings and demand response load shifting, as well as when electric vehicles are charging and discharging. The analyst will need to consider if the technology, installation cost and load shape will change when DERs are combined. The outputs for individual DERs can be compared to the DER combinations to determine the implications of integrated DER analysis and acquisition for electric system reliability, air emissions, utility system costs, and customer costs.

As discussed in the Level One analysis, the avoided cost data needed for the analysis must permit high-level temporal analysis. In its simplest form, this analysis uses daily or seasonal load shape data, or both, to allocate energy savings or generation output into peak periods and off-peak periods. Peak impacts are derived using coincidence factors. Avoided costs for the comparable daily or seasonal peak and off-peak periods are then used to determine the value of savings or generation output for those time periods. For a more detailed DER analysis, hourly avoided costs for energy and capacity may be used in conjunction with hourly load shapes and/or generation output profiles. One distinction between a Level One and Level Two analysis is that the load shapes and generation output profiles used must be consistent with the *DER combinations* being analyzed to appropriately reflect their interaction. Therefore, a Level Two analysis may require more detailed temporal data than a Level One analysis.

Depending on the purpose of the Level Two analysis, a locational analysis may be necessary. For example, if the purpose of the integrated DER analysis is to consider how to meet an identified load relief need for the distribution system, the specific distribution-related avoided cost for an identified location must be used. However, if the purpose of the Level Two analysis is only to consider if some combinations of DERs result in a benefit to the utility system or customers, use of average distribution system avoided costs may be sufficient.

The benefit of the Level Two analysis is that it allows for a simplified integrated DER analysis by excluding the interaction of DERs with the electric utility system costs. At the same time, this is the primary limitation of the analysis. Overcoming this limitation is the focus of Level Three in this analytical framework.

5. Level Three: Distributed Energy Resource Integration with Electric Utility System Resources

Level Three is the most comprehensive analysis in the framework and requires the most sophisticated modeling. Building on Level Two, all DERs that are considered in the study, in various combinations, are included in a model with electric utility system resources (e.g., utility-scale generating facilities). This analysis allows all electric system resources, both utility-scale and distributed, to be optimized. Similar to Level Two, the analysis is iterative, which may require multiple model runs. The output of the analysis will indicate various types of DER combinations that may be advantageous, depending on what the model is solving for (the stated purpose of the analysis).

Level Three analysis requires significantly more data and time, and is a more complex analysis than that conducted at Level One or Level Two. For Level One and Level Two, economic potential is established using avoided costs that are fixed across all levels and combinations of DER development. In Level Three, the analyst substitutes the fixed avoided costs with “dynamically determined” avoided costs. The dynamically determined avoided costs are created by simulating the bulk electricity system operation with various combinations of new resources, including conventional generation and DERs, to determine which mix best meets the stated goal of the analysis.

What are "dynamically" determined avoided costs?

Modern capacity expansion models use both reliability criteria and economic optimization logic to identify preferred resource portfolios. These models test alternative resource portfolios by simulating future conditions to identify the types, amounts and schedules for development of resources that meet system reliability requirements and best satisfy the model's *economic optimization* criteria.

Typically, the economic optimization criteria used in these capacity expansion models searches for the "lowest cost" resource portfolio, using the net present value of utility system revenue requirements as the cost metric. In the more sophisticated capacity expansion models, alternative resource portfolios are tested across a wide range of future conditions (e.g., load growth, fuel prices, market prices) to assess their economic risk and uncertainty. When any of these models are used to identify the economic optimal portfolio by competing DERs against supply side resources, this can (and usually does) alter the type, amount and timing for the development of supply-side resources. That is, the interaction of DERs with supply-side resources produces a different forecast of avoided costs because the portfolio is optimized from a wider array of resource options. In this sense, the avoided cost of DERs is *dynamically* determined, because adding these resources as options changes the optimization result.

Therefore, in addition to a forecast of future electricity demand, there also must be sufficient information to characterize the operating cost of the existing bulk power system and the capital and operating cost of potential resources available to meet future loads. This includes forecast of future fuel prices, wholesale electricity market prices, new generating capacity costs, the operating cost of existing electric utility system costs resources, reserve requirements, and scheduled resource retirements. While hourly load shapes or generation output profiles for all resources are needed, avoided costs are not, since the economic value of all resources is determined dynamically through the modeling process.[35] These data are important for all levels of the analysis, but in Level Three, the information will be used to model all resources dynamically. In Levels One and Two, these data will likely be provided as an existing analysis that provides the electric utility system resources and avoided costs.

Users will need to define characteristics for each type of DER as inputs in the optimization model. Combinations of DERs can be created separately and used as inputs in the optimization model, if desired. Or the model can be used to solve for the optimal combinations if it has the capacity to do so. For a more sophisticated and comprehensive analysis, locational data can be included in Level Three, but as with the other levels, such data are required only for certain analytical objectives. Depending on the purpose of analysis, locational data may be necessary.

[35] For more information on DER value, see the Mills and Wiser (2014, 2015) studies on the declining value of solar with increased adoption and mitigation strategies (e.g., combining solar with storage).

The benefit of Level Three analysis is that it provides the ability to comprehensively solve for an electric systemwide goal. The downsides of the analysis are the requirements with respect to data necessary to create robust results and resources (models, modelers and model run time) required to conduct the sophisticated modeling.

6. Examples of Integrated Analysis of DERs

This chapter focuses on examples of *integrated* analysis of DERs in electric utility system planning. Where available, we provide examples that include temporal and locational values. Appendix A provides examples of Level One analysis for each type of DER discussed in this guide.

Development and use of an integrated resource plan, or resource acquisition plan, also is a common exercise by utilities and states. All DERs may be considered within integrated resource plans, although frequently the impact of DERs may appear only as a reduction in the load forecast. This does not allow for an integrated analysis of DERs as there is little or no interaction between the resources to determine what the optimal resource mix is. Utilities and regulators can consider integrated resource planning modeling practices that allow each DER to compete on a par with all other resources.

All electric utilities perform distribution system planning, but there are limited state requirements for plans, including filing them publicly. States such as California, Hawaii and New York require regulated electric utilities to consider DERs in distribution system planning and file plans with regulators with stakeholder review. This area is rapidly evolving.[36]

6.1 Level Two Examples: Integrating Distributed Energy Resources into Demand-Side Management

Demand-side management planning is widely conducted by electric utilities in the United States, and almost all states have program administrators that publicly report energy efficiency program savings.[37] Energy efficiency and demand response are the most common DERs that are considered in demand-side management planning, although some states do also consider behind-the-meter generation resources such as solar or electric vehicles within that context.[38] Cost-benefit analysis of energy efficiency and demand response is commonly included in demand-side management planning.

The most common integrated analysis of DERs is energy efficiency and demand response considered together in demand-side management planning. For example, Berkeley Lab's recently published report on integrated demand-side management focuses on opportunities to integrate implementation

[36] Homer et al. (2017).

[37] Hoffman, Leventis, and Goldman (2017); Hoffman et al. (2018).

[38] For example, in Florida from 2009–2015, photovoltaic systems and solar water heaters were included in the utilities' energy efficiency planning.

features of energy efficiency and demand response programs to reduce costs and increase participation.[39]

A report by the U.S. Department of Energy's (DOE's) Office of Energy Systems and Policy Analysis and Evolved Energy assessed the combined impact of energy efficiency and demand response. The modeling completed for the study "indicate[s] that combining EE with flexible load [demand response] can increase the number of cost-effective energy efficiency measures available to lower system costs, compared to implementing either by itself" (see text box for more details).[40]

Interaction of Energy Efficiency and Flexible Load

The U.S. Department of Energy's Office of Energy Systems and Policy Analysis and Evolved Energy investigated the interaction of energy efficiency and flexible load resources to better understand the opportunities on a state by state basis for maximizing efficiency and demand response to create the lowest cost electric system. Findings include the following:

- Combining efficiency with flexible load (demand response) can increase the number of cost-effective measures available to lower system costs.
- Assumptions regarding distribution deferral value have a significant impact on the cost-effectiveness of measures.
- Despite a large potential for savings, a number of barriers persist to consumers who wish to adopt both energy efficiency and demand response technologies.

A recent Berkeley Lab study for the California Public Utilities Commission (CPUC) investigated demand response potential for California in 2025.[41] The study estimated the size and cost of demand response for investor-owned utilities (IOUs) in the state. Researchers used a bottom-up, customer end-use load forecasting model and demand response costs to create demand response supply curves for four grid services: Shape, Shift, Shed and Shimmy.[42]

The study considered the interactive effect between demand response and energy efficiency, and found that an energy efficient technology could increase demand response resources.[43] The illustrative example provided in the study was a heating, ventilation, and air conditioning unit that, when upgraded to an efficient unit, provided greater overall demand reduction than an inefficient unit that only participated in a demand response program.[44] The study included co-benefits of demand response and

[39] Potter, Stuart, and Cappers (2018); Goldman et al. (2010).

[40] Agan, Boyd, and Jones (2018).

[41] Alstone et al. (2017).

[42] Shape is load-modifying demand response, shift is encouraging the shift of energy consumption from times of high demand to times when there is a surplus of renewable energy generation, Shed is curtailable load demand response and Shimmy involves using loads to dynamically adjust demand. The distinction between grid services was created to enable comparisons between the cost and benefits created from having a diverse set of flexible loads.

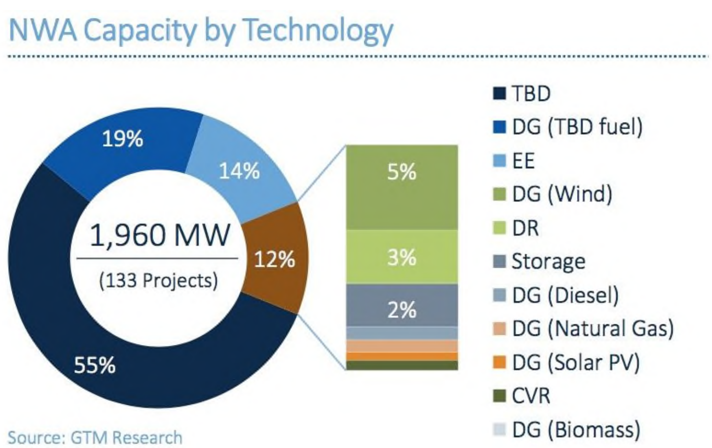
[43] Alstone et al. (2017), 8-2.

[44] The example provided in the study is as follows: Assume that an HVAC load that is 10 kW baseline can be reduced by half to

energy efficiency (e.g., bill savings from demand response device-induced energy efficiency or from a third party offering incentives), modeled as reduced upfront cost for demand response.[45]

Temporal values are frequently used in cost-benefit analysis for efficiency and demand response in demand-side management planning (i.e., through hourly avoided costs).[46] Inclusion of locational value in demand-side management planning is rare but is required to consider efficiency and demand response as non-wires alternatives to traditional distribution upgrades.[47] *Non-wires alternatives* are non-traditional investments or market operations that may defer, mitigate, or eliminate the need for traditional transmission and distribution investments. As of August 2017, 14 percent of completed or planned non-wires alternatives projects since 1991 used energy efficiency and 3 percent used demand response, as shown in Figure 3. The 55 percent of projects that are labeled "TBD" are NWA projects that have been identified or have a solicitation in progress (490 MW).

Figure 3. Non-wires alternatives (NWA) project existing and planned capacity by technology[48]



In a recent order on energy efficiency budgets for California investor-owned utilities, the CPUC articulated principles for integrating energy efficiency and demand response.[49] The principles include shifting heating, ventilating and air-conditioning usage away from peak pricing periods, ensuring there is no measure or transaction cost for a building to participate in demand response after an efficiency

5 kW with dispatchable control as demand response. If the load is made 25 percent more efficient first, the baseline load is now 7.5 kW. Assuming that can still be reduced by half, there is 3.75 kW of dispatchable control available as demand response. However, the efficient HVAC load has an overall demand reduction of 6.25 kW (2.5 kW from efficiency and 3.75 kW from demand response) and the inefficient HVAC load has a demand reduction of 5 kW.

[45] Alstone et al. (2017), 4-6.

[46] For more information on temporal analysis of DSM see Lazar and Colburn (2013).

[47] For more information on the use of locational value in DSM planning see Baatz et al. (2018) and ICF (2018).

[48] St. John (2017). A Snapshot of the US Gigawatt-Scale Non-Wires Alternatives Market. https://www.greentechmedia.com/articles/read/gtm-research-non-wires-alternatives-market#gs.nmJ9zdQ. Accessed June 22, 2018.

[49] CPUC (2018a).

upgrade, and capitalizing on co-benefits of efficiency and demand response (e.g., an efficiency device upgrade that enables demand response). The order also called for the next set of efficiency goals and potential studies to consider demand response potential.

Electric vehicles participating in a demand response program is a DER combination that is being considered in California. Southern California Edison is investigating an initial design of an electric vehicle demand response program through its Charge Ready Pilot in 2018.[50] The program requires all pilot participants with Level Two[51] charging to participate in the DR program, which seeks to meet the needs of electric vehicle customers while at the same time providing load management services for the electric grid. Southern California Edison intends to use the DR capability to help address the "duck curve" in California[52] by encouraging electric vehicle charging during periods of high solar generation and discouraging charging during steep ramping periods in the late afternoons and evenings.

While not a demand-side management planning effort, the Vermont Solar Pathways project did consider the impact of energy efficiency on the state's goal to meet 90 percent of total energy needs with renewable energy by 2050.[53] The study found that energy efficiency is a key resource for meeting the renewable energy goal.

6.2 Integrating Distributed Energy Resources into Distribution System Planning

Utilities are increasingly addressing DERs in annual (and in some cases longer-term) distribution system plans. Several states require consideration of DERs in distribution system planning as Figure 4 shows. While analysis typically is for individual types of DERs, some utilities are beginning to incorporate integrated DER analysis.

The following studies offer a broad perspective on this topic:[54]

- In 2015, Berkeley Lab published *Distribution Systems in a High Distributed Energy Resources Future*,[55] which provides a framework for states to consider DER growth and address its impacts on electric distribution systems.

---

[50] CPUC (2018d). SCE has so far deployed infrastructure for 941 charging ports.

[51] A Level One charger plugs into a standard 120 V household outlet and has a charging rate of 3-5 miles/hour. A Level Two charger requires a high voltage 240 V circuit (similar to what is used for a washer or dryer) and has a charging rate of 12-75 miles/hour.

[52] The duck curve shows the difference between electricity demand and available solar energy throughout the day. https://www.energy.gov/eere/articles/confronting-duck-curve-how-address-over-generation-solar-energy.

[53] Hill et al. (2016).

[54] See the appendix for more examples of studies on DERs and distribution system planning.

[55] De Martini et al. (2016).

- In 2016, DOE commissioned a report, *Integrated Distribution Planning,*[56] by ICF for the Minnesota Public Utilities Commission. It discusses in part hosting capacity analysis, scenarios for distribution system planning and locational net benefits assessment.
- A December 2017 study by Pacific Northwest National Laboratory, Berkeley Lab, and National Renewable Energy Laboratory for DOE's Grid Modernization Lab Consortium, *State Engagement in Electric Distribution System Planning,*[57] documents activities in 16 states related to distribution system planning, as summarized in Figure 4. A newer 2018 study reorganizes the original material by subject and incorporates updated information.[58]
- A forthcoming report discusses current practices for hosting capacity analysis and locational value assessment for DERs.[59]

Berkeley Lab has archived presentations for trainings it organizes on distribution systems and planning for public utility commissions and state energy officials across the country.[60] Topics range from forecasting load with DERs to emerging planning analyses, with citations to utility distribution system plans and related studies.

Figure 4. State engagement in distribution system planning[61]

	States with advanced practices					Other state approaches										
	California	Hawaii	Massachusetts	Minnesota	New York	D.C.	Florida	Illinois	Indiana	Maryland	Michigan	Ohio	Oregon	Pennsylvania	Rhode Island	Washington
Statutory requirement for long-term distribution plans or grid modernization plans(a)	✓			✓					✓							
Commission requirement for long-term distribution plans or grid modernization plans(a)		✓	✓		✓					✓	✓					
No planning requirements yet, but proceeding underway or planned						✓							✓		✓	✓
Voluntary filing of grid modernization plans								✓				✓		✓		
Non-wires alternatives analysis and procurement requirements	✓				✓										✓	
Hosting capacity analysis requirements	✓	✓		✓	✓											
Locational net benefits analysis required	✓				✓											
Smart grid plans required													✓			
Required reporting on poor-performing circuits and improvement plans							✓	✓				✓		✓	✓	
Storm hardening requirements							✓			✓						
Investigation into DER markets		✓														

(a) For one or more utilities.

[56] Integrated distribution planning assesses physical and operational changes to the electric distribution system necessary to enable safe, reliable and affordable service that satisfies customers' changing expectations and use of DERs, generally in coordination with resource and transmission planning. Such planning also includes stakeholder-informed planning scenarios to support a robust grid in a changing and uncertain future.

[57] Homer et al. (2017).

[58] Cooke, Homer, and Schwartz (2018).

[59] ICF (2018).

[60] See, for example, Schwartz et al. (2018a).

[61] Figure by Schwartz, in Homer et al. (2017).

DERs are considered in tandem with distribution system planning in several ways, including distribution and DER plans, hosting capacity analysis, locational net benefits analysis, and non-wires alternatives. Each of these is discussed in more detail below.

6.2.1 Distribution and Distributed Energy Resource Plans

New York

As part of the New York Reforming the Energy Vision process, the New York Public Service Commission (NYPSC) in Docket/Case 14-M-0101 ordered IOUs within the state to file Distribution System Implementation Plans. Most recently, the Department of Public Service released a staff whitepaper in April 2018 providing guidance on Distribution System Implementation Plans. The whitepaper provides details for incorporating storage, electric vehicles, and energy efficiency into these plans. For storage, one criteria requires the utilities to include a description of "the means and method for determining the real-time status, behavior and effect of energy storage resources in the distribution system."[62] Regarding electric vehicles, the Distribution System Implementation Plans staff called for a common framework that is jointly developed by the utilities to "identify and characterize the existing and anticipated EV charging scenarios by the utility's service territory."[63] Scenario characterizations include location, types of electric vehicles, and number of vehicles being charged.

Energy efficiency must be included in the Distribution System Implementation Plans, including "the resources and capabilities used for integrating energy efficiency within system and utility business planning, including among other things, infrastructure deferral opportunities as part of NWAs, peak and load reduction and/or energy shaping with an explanation of how integration is supported by each of those resources and capabilities, or other shared savings/benefits opportunities."[64]

Nevada

In 2017, Nevada passed a law that requires utilities to file their first distributed resources plan by April 1, 2019. Distributed resource plans must be part of integrated resource planning, and must include five components: "(1) evaluate locational benefits and costs of distributed resources; (2) propose or identify standard tariffs, contracts or other mechanisms for the deployment of cost-effective distributed resources; (3) propose cost-effective methods of effectively coordinating existing programs approved by the Commission; (4) identify additional spending necessary to integrate cost-effective distributed resources into distribution planning; and (5) identify barriers to the deployment of distributed resources."[65] The Public Utilities Commission of Nevada opened a docket to implement the law in 2017 and in June 2018, following a stakeholder process, the utility NV Energy submitted proposed regulations for including the Distributed Resource Plan within the triennial integrated resource plan, with annual updates.[66]

---

[62] NY DPS (2018b), 14.
[63] NY DPS (2018b), 18.
[64] NY DPS (2018b), 19.
[65] Nevada Senate Bill 146 (2017).
[66] Docket 17-08022; http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2017-8/30483.pdf.

Sacramento Municipal Utility District (SMUD)

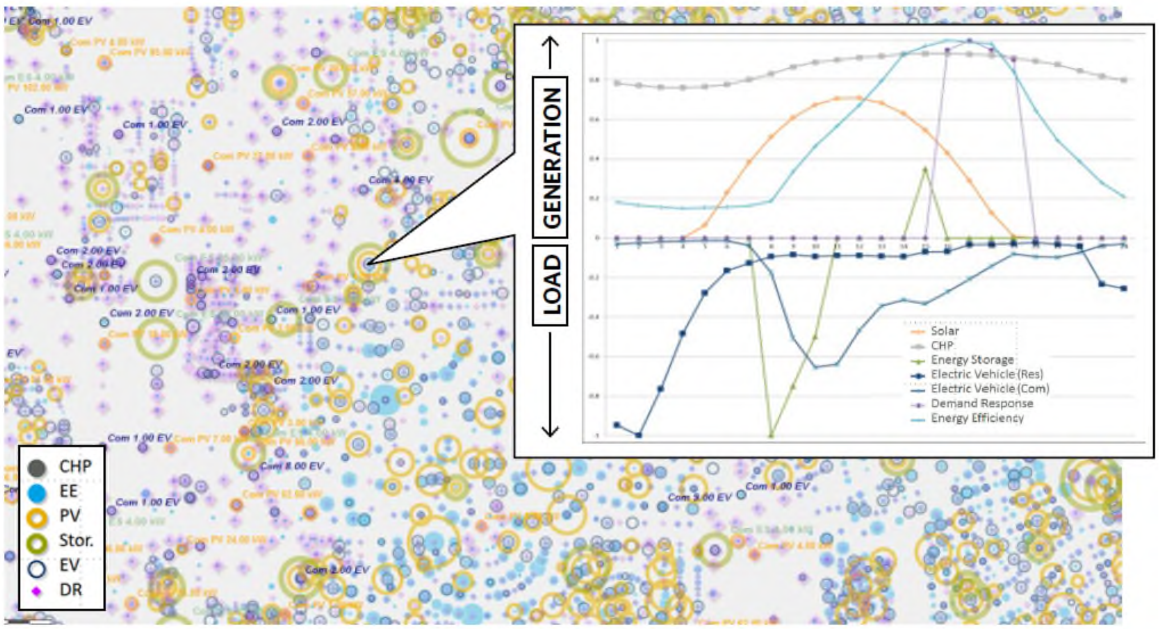
SMUD and Black & Veatch conducted an integrated DER planning study in 2017 to assess the impact of DERs on SMUD's system. The goal of the study was to identify opportunities to engage customers, maximize net benefits of DERs, and address risks presented by DERs. The study built on a DER planning process established in prior research by considering interaction of DERs. Technologies considered in the study included combined heat and power, distributed solar PV, distributed energy storage, energy efficiency, demand response and electric vehicles.

Black & Veatch developed a customer database including information on customer's historical DER adoption, building characteristics, electricity use, customer demographics, customer segment and meter locations. Using SMUD's technical, economic and achievable potential for each DER and customer database, Black & Veatch identified the technical and economic potential of each DER technology for each customer. In addition, Black & Veatch assigned an "adoption propensity" value to each customer based on their characteristics.

Next, the study assigned actual adopters based on a random number generator. If a customer was selected, then the system size was based on the customer's specific DER potential for the chosen technology. After customers were assigned a DER technology and the systems were properly sized based on the technical and economic potential, an operation profile was assigned to each adopter. The study created 65 hourly load profiles. This resulted in customer-level DER adoption maps and circuit-level impact maps.

Figure 5 shows an example customer-level DER adoption map. Each colored circle represents a type of DER technology forecasted to be adopted at a particular site. The legend shows the color that represents each DER technology, with the size of the circle representing the proportional output of the DER. More than one circle at a site indicates forecasted adoption of multiple DER technologies.

Figure 5: Map of residential and commercial DER adoption forecast for a section of SMUD territory, with example hourly DER profiles[67]



The study indicated that DER adoption was likely to be widespread throughout SMUD territory, but unevenly distributed. Clusters of high DER adoption are expected to be driven by a combination of demographics, technical and economic factors. Understanding this clustering could help SMUD proactively plan for distribution upgrades and engage with customers early on solutions to mitigate impacts. The utility is using the maps to assess distribution and bulk level impacts and understand potential financial impacts of DER adoption.

6.2.2 Hosting Capacity Analysis

Hosting capacity analysis establishes the amount of DERs that can be interconnected to the distribution grid without adversely affecting power quality or reliability under existing control and protection systems and without infrastructure upgrades. This type of analysis is required in California ("Integration Capacity Analysis"), Hawaii, Minnesota and New York, and some utilities (e.g., Pepco) perform the analysis on their own initiative. EPRI published a study in 2015 that provided a hosting capacity method focusing on voltage and protection as the basis for ensuring effective DER integration.[68] More recently, the Interstate Renewable Energy Council released a report offering use cases and considerations for evaluating and selecting methodologies for hosting capacity analysis.[69]

[67] Black & Veatch (2017).
[68] Rylander, Rogers and Smith (2015).
[69] IREC (2017).

6.2.3 Locational Net Benefits Analysis

Locational net benefits analysis evaluates location-specific DER benefits and costs to inform DER procurement, pricing and programs.[70] It is the systematic analysis of costs and benefits of a specific combination of DERs associated with a distribution substation, an individual feeder, a section of a feeder or a combination of these components. California, New York and Hawaii have articulated approaches to quantify the locational value of DERs.[71]

- California: A working group process is developing modeling tools for locational net benefits analysis, including demonstration projects to test and identify location-specific values.[72] The CPUC directed that valuation should be modified to reflect more location-specific information, such as avoided capital and operating expenditures for:[73]
  - Distribution voltage and power quality
  - Distribution reliability and resiliency
  - Subtransmission, substations and feeders
  - Transmission

- New York: The Public Service Commission is developing "value stack" tariffs that in part reflect the locational value of DERs — identifying, quantifying and compensating for locational system relief value zones. These tariffs will initially replace net metering for larger-scale community solar PV projects and eventually are expected to be applied to all DERs.[74]

- Hawaii: Hawaiian Electric Companies is planning an Integrated Grid Planning and Solution Sourcing Process, accounting for locational impacts and value of DERs in evaluation of non-wires alternatives to traditional investments.[75]

A recent report by ICF for DOE identifies three use cases for locational net benefits analysis (see Table 2) and associated capabilities and challenges.[76] The primary use case is a competitive solicitation of non-wires alternatives for deferral of traditional utility distribution system investments.

Tariffs that provide incentives based on DER value for distribution system planning are also a use case for locational net benefits analysis, although implementation is limited. In California, the CPUC required IOUs to identify tariffs to deploy DERs.[77] New York has created a value of DER tariff to replace net

[70] De Martini et al. (2016); ICF (2018).
[71] Cooke, Homer, and Schwartz (2018).
[72] California's Distribution Resources Plan [R. 14-08-013]. https://drpwg.org/sample-page/drp/
[73] CPUC (2015).
[74] NY DPS (2017a).
[75] Hawaiian Electric Companies (2018).
[76] ICF (2018).
[77] CPUC (2018b).

metering and eventually to be applied to all DERs.[78] Hawaiian Electric Companies proposed in its Integrated Grid Plan to consider market-based solutions and tariffs to procure necessary resources.[79]

Table 2. Use cases for locational net benefits analysis (adapted from ICF)

Non-Wires Alternatives	Procure non-wires alternatives to defer T&D investment
Tariff Design	Link locational value analysis to tariff design
Program Design	Targeted program customer acquisition and/or incentives

6.2.4 Non-wires alternatives

Non-wires alternatives are nontraditional investments or market operations that may defer, mitigate or eliminate the need for traditional transmission and distribution investments. Several states (e.g., New York, California, Rhode Island, Nevada) require consideration of non-wires alternatives in distribution system planning.[80] There is a growing body of literature on the implementation and success of using DERs to cost-effectively defer distribution system upgrades. The most well-known example is Consolidated Edison's Brooklyn Queens Demand Management project which successfully deferred $1.2 billion of traditional network upgrades (41 megawatts [MW] customer-side, 11 MW utility-side) using a combination of energy efficiency (primarily), voltage optimization, battery storage and other DERs.[81] Also in New York, the Joint Utilities provided suitability criteria for non-wires alternatives projects in March 2017[82] and described how the criteria will be applied to projects in their capital plans in a supplemental filing in May 2017.[83] Consolidated Edison, Orange and Rockland Utilities, and Central Hudson non-wires alternatives criteria are similar.

Utilities are studying how to use DERs to defer distribution infrastructure in Oregon and Rhode Island as well. In Oregon, Pacific Power and the Energy Trust of Oregon are using targeted energy efficiency to test potential deferral of a distribution substation upgrade. The two-year pilot targets 3,000 residential, commercial and industrial customers to reduce substation load through energy efficiency. The pilot has four goals: (1) measure and quantify peak demand savings, (2) document and evaluate the ability to replicate the targeted efficiency strategy in other regions served by Pacific Power and the Energy Trust of Oregon, (3) develop processes for coordinated implementation between Pacific Power and the Energy Trust of Oregon, and (4) determine if changes need to be made to improve targeted deployment of traditional distribution system upgrades.

[78] NY DPS (2018b).
[79] Hawaiian Electric Companies (2018).
[80] Homer et al. (2017); Schwartz and Mims (2018); Schwartz (2018b).
[81] IEEE (2017); Con Edison (2015)
[82] NY DPS (2017b).
[83] NY DPS (2017c).

In Rhode Island, a System Reliability Procurement pilot focused on the use of distributed solar to defer distribution system infrastructure investment.[84] In May 2018, Cadmus completed an evaluation of the pilot program to determine actual peak load reductions on the distribution system. The impact evaluation found that in 2017, for every direct current kilowatt of west-facing rooftop solar installed, the coincident peak decreased by 0.28 alternating current kilowatt. The study also found that west-facing systems had higher coincident peak output than south-facing systems, and that the distribution system feeders included in the study had a maximum peak load later between 5 and 7 pm, when solar production was low. However, by broadening the range of hours to the top 10 percent of hours with the highest loading, solar production did reduce peak. Cadmus found that solar reduced the distribution peak by 10 kW and 130 kW in 2017, as Table 3 shows.

Table 3. Capacities installed, capacity factor during max loading hour, total output during max loading hour, and percentage reduction in feeder loading (2016 and 2017)

System Type	Orientation	Summer 2016, Max Hour of 17.5MWh				Summer 2017, Max Hour of 15.4MWh			
		Installed Capacity, kW-DC	Capacity Factor, kW-AC/ kW-DC	Output at Max Load Hour, kW-AC	Reduction of Max Load	Installed Capacity, kW-DC	Capacity Factor, kW-AC/ kW-DC	Output at Max Load Hour, kW-AC	Reduction of Max Load
Roof-Mounted	South	58.7	5%	2.68	0.015%	87.5	15%	13.4	0.087%
	Southwest	39.2	9%	3.59	0.021%	60.1	26%	15.6	0.101%
	West	31.8	14%	4.34	0.025%	30.1	34%	10.2	0.066%
Ground-Mounted	n/a	n/a	n/a	n/a	n/a	249.9	38%	94.6	0.615%
Measured Total		129.7	8%	10.61	0.061%	427.6	31%	133.7	0.869%
Extrapolated to Program*		395.2	8%	30.80	0.17%	645.0	28%	182.1	1.18%

* To estimate the impact of the whole program, residential roof-mounted systems that were not monitored were included such that their generation rate was the same as their azimuth group (i.e., south, southwest, west). For 2016, the ground-mounted system was not included, but all 57 residential systems that were to received incentives were included. For 2017, the extrapolation also includes the ground-mounted system.

Cadmus also considered storage combined with solar as a strategy for distribution system load reduction and found that 268 storage systems (5 kW each) would have been needed to achieve a 5 percent peak load reduction in 2016, and 154 units in 2017.

A 2017 Nevada law[85] requires deployment of cost-effective DERs that satisfy distribution planning objectives. Among other requirements, NV Energy will annually update a grid needs assessment with analysis of non-wires alternatives as part of distributed resource plans.[86]

6.3 Integrating Distributed Energy Resources in Resource Planning

Accurate inclusion of DERs in integrated resource planning is an increasingly important consideration for electric system planners. For example, a report by National Renewable Energy Laboratory and Berkeley Lab on distributed solar PV adoption forecasts in utility resource planning found that

---

84 Cadmus (2018).

85 SB 146. https://www.leg.state.nv.us/App/NELIS/REL/79th2017/Bill/4982/Text.

86 See Nevada Public Utilities Commission Docket No. 17-08022 at http://pucweb1.state.nv.us/puc2/Dktinfo.aspx?Util=All.

misforecasting distributed PV in utility system planning increases costs for utilities and ratepayers. The results are asymmetrical, with underforecasting distributed PV adoption resulting in higher system costs than overforecasting adoption. The study provides a simplified probabilistic method that utilities can use to estimate cost savings from reducing uncertainty of distributed PV forecasts.[87]

Some regulators explicitly require utilities to consider at least one type of DER in integrated resource planning or other long-term planning, including:

- Massachusetts Department of Public Utilities issued an order on grid modernization that clarified the objective of including DERs to "facilitate the interconnection of distributed energy resources and to integrate these resources into the Companies' planning and operations processes."[88]
- Washington Utilities and Transportation Commission requires that utilities use identified DERs as inputs to integrated resource planning.[89]
- The Oregon Public Utility Commission issued an order on Portland General Electric's integrated resource plan in October 2017 that required the utility to "work with Staff and other parties to advance distributed energy resource forecasting and distributed energy resource representation in the IRP process."[90]
- New Orleans City Council requires Entergy New Orleans to consider storage and other DERs as potential supply side resources in integrated resource planning.[91]
- New Mexico requires energy storage to be considered with other resource options in integrated resource planning.[92]
- Michigan Public Service Commission's Integrated Resource Plan Parameters require regulated utilities to consider distributed solar, efficiency and demand response on equal footing as supply-side resources.[93]
- Indiana requires that the utility's integrated resource plan include the costs of meeting future electric growth with efficiency, load management, distributed generation and cogeneration.[94]
- California, Georgia, Iowa, Indiana, Kentucky, Michigan, Nebraska, Nevada, New Mexico and Oregon require consideration of combined heat and power in integrated resource planning.[95]

---

[87] Gagnon et al. (2018).

[88] Massachusetts Department of Public Utilities Docket No 15-120. May 10, 2018, Order at 104.

[89] WUTC (2017a,b).

[90] Oregon Public Utility Commission Docket No. LC 66, Order 17-386, page 19.

[91] Resolution R-17-410 Amending the Electric Utility Integrated Resource Plan Rules. https://www.all4energy.org/uploads/1/0/5/6/105637723/2017_07_26_ud-17-01_cno_resolution_r-17-410_amending_the_electric_utility_integrated_resource_plan_rules.pdf.

[92] Final Order Amending Integrated Resource Planning Rules 17.7.3 NMAC to Include Energy Storage Resources. http://164.64.85.108/infodocs/2017/8/PRS20243548DOC.PDF.

[93] Integrated Resource Plan Statewide Parameter Setting/Modeling. https://www.michigan.gov/mpsc/0,4639,7-159-80741_80743-406248--,00.html.

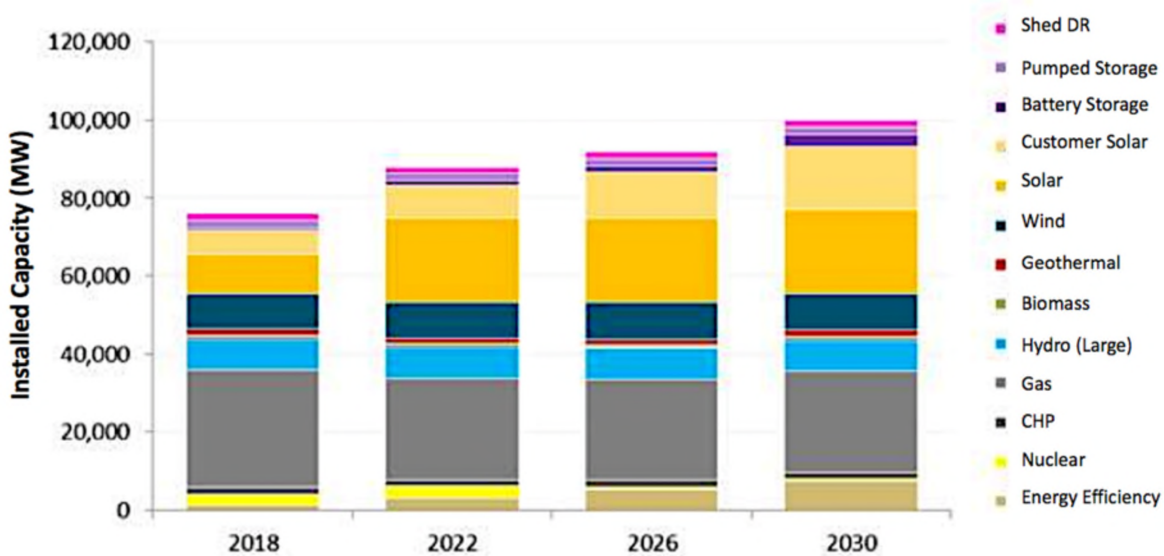
[94] IN Code § 8-1-8.5-3 (2017).

[95] https://www.naseo.org/data/sites/1/documents/publications/CHP-for-State-Energy-Officials.pdf, Michigan PA 341 (2016).

Following are examples from California, the Pacific Northwest, Nevada, Arizona and Hawaii of utilities incorporating DERs into integrated resource planning.

Senate Bill 350 (2015) required the CPUC to adopt a process for integrated resource planning. In an ongoing rulemaking, the CPUC is developing an integrated resource planning framework.[96] As part of this effort, the CPUC developed a reference system plan to provide general direction to load serving entities on how to model their integrated resource plans by providing the main conclusions drawn from CPUC staff's analytical work. The CPUC staff used a production cost model to create the reference system plan, which is the optimal portfolio of resources that will achieve electric sector greenhouse gas reductions, reliability needs, and other policy goals at least cost under a variety of possible future conditions.[97] In a February 2018 order, the CPUC found that the reference system plan (represented in Figure 6) was a reasonable guide for integrated resource planning in 2018.[98] Load serving entities must still meet their own energy efficiency, renewable portfolio standard and resource adequacy requirements, so the reference system plan only provides guidance for their integrated resource plan modeling. The reference system plan includes several DERs: customer-sited solar, battery, energy efficiency, combined heat and power and shed demand response.

Figure 6. CPUC total capacity of resources in a reference system portfolio



The CPUC is also working toward coordination between DER planning and integrated resource planning. The CPUC ordered in February 2018 that the utilities must use updated DER forecasts from the most recent California Energy Commission Integrated Energy Policy Report in the next distribution planning cycle, and that the commission will "consider the implications of the IRP Reference Plan and what additional DER scenarios may be necessary in future distribution planning cycles as we further examine

96 CPUC Docket Number 16-02-007.

97 CPUC (2018c).

98 CPUC (2018c).

the relationship between DRP [distribution resource planning], IRP [integrated resource planning], and IDER [integrated distributed energy resources] to create a cohesive DER planning and procurement framework."[99]

In the Pacific Northwest, the Northwest Power and Conservation Council's Regional Portfolio Model for the *Seventh Power Plan* considered energy efficiency, demand response and distributed solar with supply-side resources. Energy efficiency measures were first bundled together into multiple levelized cost bins to reduce the model run time, and then all three types of DERs were included as inputs in the model. The model tested developing different cost levels (and subsequently different amounts) of each resource in combination with each other, and with conventional generation and market purchases. Alternative resource portfolios consisting of various combinations of conventional generation resources, energy efficiency, demand response and distributed solar were tested across 800 possible futures. The model tested thousands of combinations of type, amount and timing of resources before selecting an optimum portfolio. The goal of the Council's modeling process is to identify the resource portfolio (i.e., type, amount and timing of resource development) that results in the lowest *expected cost*[100] to the region across all of the futures tested. The *Seventh Power Plan* found that by 2035, distributed PV could lower peak summer impacts by 600 MW, energy efficiency should be used to meet 37,000 gigawatt-hours (GWh) (4,300 average MW) of annual load,[101] and a minimum of 700 MW of demand response should be developed within five years to meet regional resource adequacy standards.[102]

In March 2018, Hawaiian Electric Companies submitted its Integrated Grid Planning Report to the Hawaii Public Utilities Commission as part of its Grid Modernization Strategy. The goal of the Integrated Grid Planning effort is to "integrate the needs at all levels of the system: customer, bulk power resources, transmission and distribution" and "engage customers and stakeholders at key junctures in the integrated resource, transmission and distribution planning efforts."[103] Hawaiian Electric Companies also proposes to integrate market-based solutions into the process as Figure 7 shows.

99 CPUC (2018c), 22.

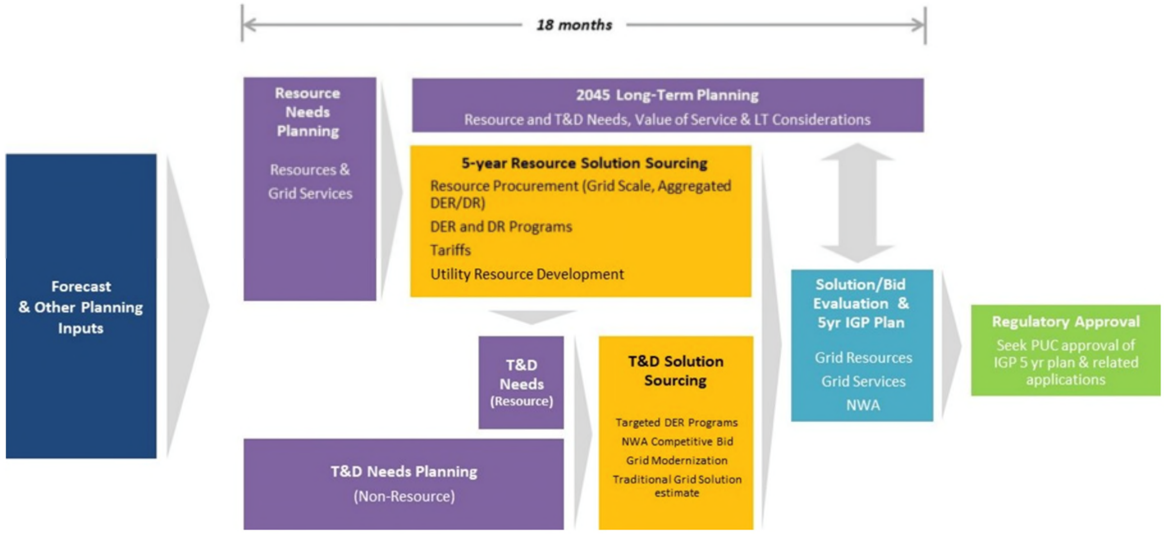
100 The Council's Regional Portfolio Model uses Monte Carlo simulation techniques to identify resource portfolios which have the *highest probability* of being the lowest cost across all futures tested. Since actual future conditions will take only one path, this does not ensure that these resource portfolios ***will be*** the lowest cost.

101 "Megawatt is the standard term of measurement for bulk electricity. One megawatt is 1 million watts. One million watts delivered continuously 24 hours a day for a year (8,760 hours) is called an 'average annual megawatt.'" https://www.nwcouncil.org/history/megawatt/.

102 Northwest Power and Conservation Council. Seventh Northwest Power Plan. February 2016. https://www.nwcouncil.org/reports/seventh-power-plan.

103 Hawaiian Electric Companies (2018).

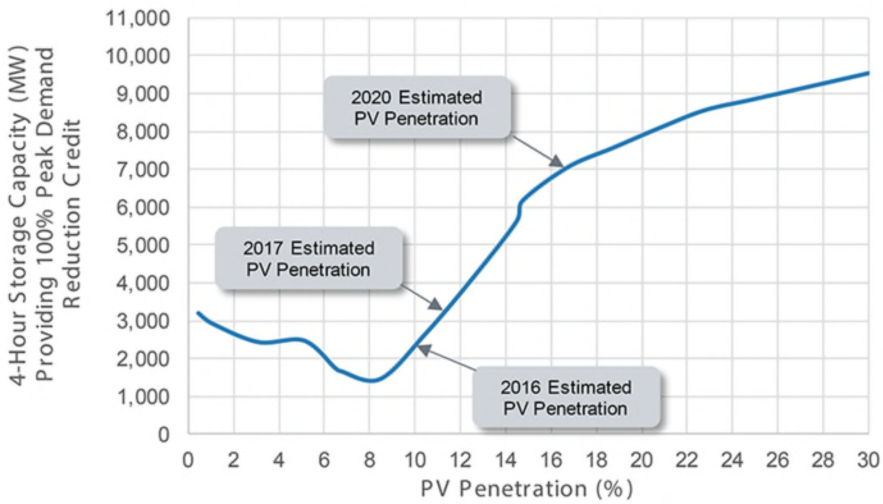
Figure 7. Hawaiian Electric Companies' integrated grid planning and solution sourcing process



Finally, although not studied specifically for integrated resource planning, a recent study by National Renewable Energy Laboratory on the impact of combining distributed and utility scale solar and storage shows that coupling the resources results in greater peak demand reductions. The study first determined the ability of storage to reduce peak demand, and then reviewed the capacity impact of including and excluding solar. Researchers found that in California, if solar penetration is below 11 percent (of electricity production), it reduces the four-hour storage potential[104] because it flattens the load. At about 17 percent PV penetration, four-hour storage in California more than doubles when compared with the case that excludes solar, as Figure 8 shows.

[104] The California Public Utilities Commission applies full resource adequacy credit to storage that can operate for four or more consecutive hours at maximum power output.

Figure 8. Capacity of four-hours that can provide 100 percent peak reduction, by photovoltaic penetration level[105]



7. Estimated Distributed Energy Resource Potential Study Cost

The cost of potential studies varies widely. Factors that influence the cost include the number of resources being considered, the amount of existing or primary data used, the size of the geographic area and number of utility service areas being assessed, use of scenarios and sensitivities, and any integration of the study with other planning efforts such as IRP or distribution system planning. As discussed throughout this guide, few potential studies conduct an integrated analysis of DERs. Thus, most of the examples provided in Table 4 are potential studies that consider one or more DER, without considering integration. Estimates in the table from consultants and a municipal utility are from interviews Berkeley Lab conducted for this project.

[105] Denholm and Margolis (2018).

Table 4. Estimated DER potential study budget and scope

Organization	Resource	Estimated Budget	Scope
Consultant	Demand response	$100,000–150,000	• One utility • Scope limited to DR and associated measures (EVs and storage) • Limited consideration of how resources interact
Consultant	Energy efficiency, demand response, distributed generation, storage	$300,000–$500,000	• One utility • Cost estimate assumes information for baseline market assessment is available and adequate • Limited consideration of how resources interact
Consultant	Energy efficiency, demand response, distributed generation, storage	$750,000–$1,000,000	• One utility • Cost estimate assumes primary data must be gathered for baseline market assessment • Limited consideration of how resources interact
CPUC[106]	Energy efficiency	$2.7 million	• Technical, economic and market potential for three IOUs in California • Used to inform CPUC energy efficiency (EE) goal-setting process • Five scenarios considered • Stakeholder engagement
CPUC[107]	Demand response	$2.9 million	• Identified DR potential for three IOUs in California • Phase 1 identified peak shedding DR potential • Phase 2 identified DR potential to meet capacity, energy and ancillary services • Technical Advisory Group
Hawaii Public Utilities Commission (2014)[108]	Energy efficiency	$335,000	• Statewide technical and economic EE potential study • Identified EE potential that can be used a resource in IRP • Results reported by utility service territory and by island

[106] CPUC (2017).
[107] Alstone et al. (2017).
[108] Rohmund, Kester, and Nguyen (2014).

Table 4. Estimated DER potential study budget and scope (continued)

Organization	Resource	Estimated Budget	Scope
Minnesota Department of Commerce (DOC) (ongoing)[109]	Energy efficiency	$1.4 million	• Statewide natural gas and electric efficiency and CO_2 reduction potential for 2020–2029 • Technical, economic, achievable and program potential • Inform utilities which emerging technologies, program delivery models, key market sectors, and policy approaches to target to maximize efficiency • Stakeholder engagement
Minnesota DOC[110] (2014)	Combined heat and power	$205,000	• Statewide technical and economic potential, and economic potential with policy options for 2014–2040 • Used to assess changes in state policy to increase implementation of CHP
Massachusetts Department of Energy and Resources (2016)[111]	Storage	$400,000	• Identified market opportunities and economic benefits of energy storage for the state • Examined policies and programs to support storage deployment • Stakeholder engagement
Municipal utility in the West	Solar	$210,000	• One municipal utility territory • Technical potential of distributed solar • Analysis included customer adoption over time with different rate structures
Northwest Power and Conservation Council[112]	Distributed solar, efficiency, demand response, storage, conventional utility scale generation	$4–$5 million	• Budget is for the entire Seventh Power Plan, which covers four states (OR, WA, ID, MT) • Additional funding (~$2–$4M) is used for data (e.g., end-use load shape research by Northwest Energy Efficiency Alliance, Regional Technical Forum) • Study optimizes resources in integrated analysis • Budget is multiyear and covers significant analysis

[109] Statewide Energy Efficiency Demand-Side Potential Study. About the Study. https://www.mncee.org/mndemandstudy/about/
[110] Spurr, Sampson, and Wang (2014).
[111] Massachusetts Department of Energy Resources (2016).
[112] NWPCC (2016).

Table 4. Estimated DER potential study budget and scope (continued)

Organization	Resource	Estimated Budget	Scope
New Mexico (2011)[113]	Energy efficiency, demand response	$700,000	• Statewide efficiency and demand response potential study for electric and gas utilities • Residential and commercial customer surveys • Stakeholder engagement
Pennsylvania PUC (2015)[114]	Energy efficiency	$686,000	• Seven investor-owned utilities • Technical, economic, achievable and program potential savings for 2016–2025
VEIC (2017)[115]	Distributed solar, efficiency, wind, conventional utility scale generation, flexible load, storage	$740,000	• Investigation of 20 percent of Vermont electricity from solar by 2025, and the interaction with efficiency and other supply options • Cost and savings from perspective of society at large • Characterization of supply demand imbalance • Project bill "at cost" below normal consulting rates • RAP and VT Department of Public Service were partners

113 Rohmund and Kester (2011).

114 Pennsylvania Statewide Evaluation Team (2015).

115 Hill et al. (2016).

8. Observations and Next Steps

Integrated analysis of DERs in electric utility system planning may identify a least-cost resource mix and DER opportunities that would otherwise be missed when planning these resources in isolation. However, the high fidelity of requisite data, which may include temporal and locational value, and complex modeling required to integrate multiple DERs into electric utility system planning, may be challenging and time consuming. Examples of integrated analysis of DERs provide limited guidance. Potential opportunities for publicly available research include:

- Guidelines for DER benefit-cost analysis
- Interactive effects of combinations of DERs for demand-side management planning, distribution system planning and resource planning
- Necessary key assumptions for creation of combinations of DERs for Level Two analyses (analysis of two or more DERs with a fixed electric utility system) and Level Three (analysis of two or more DERs with a dynamic electric utility system)
- A clearinghouse of case studies, as examples of integrated DER analysis grow, that makes the information more readily available to states, utilities and stakeholders
- Identifying and categorizing key policy drivers to promote integrated DER analysis in electric utility system planning

References

Agan, J., E. Boyd, and R. Jones. 2018. Energy Efficiency & Flexible Load in Buildings: Integrating Demand-Side Technology Assessments. Washington, D.C.: DOE Office of Energy Systems and Policy Analysis. https://docs.wixstatic.com/ugd/a35761_2064b7e5b28c416fb3141752790f5296.pdf

Al-Alawi, Baha M., and Thomas H. Bradley. "Review of Hybrid, Plug-in Hybrid, and Electric Vehicle Market Modeling Studies." *Renewable and Sustainable Energy Reviews*, vol. 21, May 2013, 190–203. doi:10.1016/j.rser.2012.12.048. https://www.sciencedirect.com/science/article/pii/S136403211300004X

Alstone, P. J. Potter, M. A. Piette, P. Schwartz, M. Berger, L. Dunn, S. Smith, M. Sohn, A. Aghajanzadeh, S. Stennsson, J. Szinai, T. Walter, L. McKenzie, L. Lavin, B. Schneiderman, A. Mileva, E. Cutter, A. Olson, J. Bode, A. Ciccone, and A. Jain. 2017. *Final Report on Phase 2 Results: 2025 California Demand Response Potential Study.* San Francisco, CA: California Public Utilities Commission. http://www.cpuc.ca.gov/General.aspx?id=10622

Baatz, B., G. Relf, and S. Nowak. 2018. *The Role of Energy Efficiency in a Distributed Energy Future*. Washington, D.C.: American Council for an Energy Efficient Economy. http://aceee.org/research-report/u1802

Black & Veatch. 2017. *Volume II: A Case Study of Integrated DER Planning by Sacramento Municipal Utility District*. Washington, D.C.: Smart Electric Power Alliance. https://sepapower.org/resource/beyond-meter-planning-distributed-energy-future-volume-ii/

Boyd, E. 2017. Power Sector Modeling 101. Washington, D.C.: Department of Energy Office of Energy Systems and Policy Analysis. https://energy.gov/sites/prod/files/2016/02/f30/EPSA_Power_Sector_Modeling_FINAL_021816_0.pdf

Cadmus. 2018. *System Reliability Procurement Distributed Generation Pilot Evaluation Final Report.* Providence, RI: Rhode Island Office of Energy Resources. http://www.energy.ri.gov/documents/SRP/2018-srp-dg-pilot-emv-final-report.pdf

California Energy Commission (CEC) staff. 2017. *2017 Integrated Energy Policy Report (IEPR)*. California Energy Commission. CEC-100-2017-001-CMF. http://www.energy.ca.gov/2017_energypolicy/

California Public Utilities Commission (CPUC). 2015. Distribution Resource Planning Rulemaking 14-08-013. Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M146/K374/146374514.PDF

CPUC. 2017. Energy Efficiency Potential and Goals Study for 2018 and Beyond. San Francisco, CA: Navigant for CPUC. http://www.cpuc.ca.gov/General.aspx?id=6442452619

CPUC. 2018a. Application of Southern California Edison Company for Approval of Energy Efficiency Rolling Portfolio Business Plan. Decision Addressing Energy Efficiency Business Plans, Decision No 18-05-041.
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M215/K706/215706139.PDF

CPUC. 2018b. DRP Proceeding 14-10-003 – Track 3, Sub-track 1: DER Growth Scenarios. Decision No. 18-02-004, issued February 15, 2018, at
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K858/209858586.PDF

CPUC. 2018c. Rulemaking 16-02-007. Order Instituting Rulemaking to Develop and Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements. Decision 18-02-018, Setting Requirements for Load Serving Entities Filing Integrated Resource Plans. Issued February 13, 2018.
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K771/209771632.PDF

CPUC. 2018d. Application of Southern California Edison Company for Approval of its Charge Ready 2 Infrastructure and Market Education Programs.
http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/269F29887CEF2390882582C20065927E/$FILE/A1806015-SCE-01-Charge%20Ready%202%20Testimony.pdf

Cole, W., T. Mai, P. Donohoo-Vallett, J.Richards, and P. Das. 2017. 2017 Standard Scenarios Report: A U.S. Electricity Sector Outlook. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-68548. https://www.nrel.gov/analysis/data-tech-baseline.html

Consolidated Edison (Con Ed). 2015. *BQDM Quarterly Expenditures & Program Report,* Q2.
http://www.coned.com/energyefficiency/pdf/Q2-2015-BQDM-quarterly-report-FINAL.pdf

Cooke, A., J. Homer, and L. Schwartz. 2018. Distribution System Planning – State Examples by Topic. PNNL-27366. Berkeley, CA: Lawrence Berkeley National Laboratory.
https://emp.lbl.gov/publications/distribution- planning-state

Corfee, K., S. Goffi, and A. Romano. 2016. *Private Generation Long-Term Resource Assessment (2017–2036).* San Francisco, CA: Navigant prepared for PacifiCorp.
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/PacifiCorp_IRP_DG_Resource_Assessment_Final.pdf

De Martini, P., L. Kristov, and L. Schwartz (editor). 2016. *Distribution Systems in a High Distributed Energy Resources Future.* Berkeley, CA: Lawrence Berkeley National Laboratory.
https://emp.lbl.gov/sites/all/files/lbnl-1003797.pdf

Denholm, P., and R. Margolis. 2018. *The Potential for Energy Storage to Provide Peaking Capacity in California under Increased Penetration of Solar Photovoltaic.* Golden, CO: National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy18osti/70905.pdf

Eckman, T., and L. Schwartz. 2018. *Review of IRP software under consideration by Minnesota utilities to assess model capacity to address high-priority analytical questions and issues.* Berkeley, CA: Lawrence Berkeley National Laboratory. Memo to Minnesota Public Utilities Commission.

Energy Information Administration (EIA). 2017. Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017. April. https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf

Energy Policy Act of 1992. http://www.ferc.gov/legal/maj-ord-reg/epa.pdf

Electric Power Research Institute (EPRI). 2017a. *Systems Analysis in Electric Power Sector Modeling: A Review of the Recent Literature and Capabilities of Selected Capacity Planning Tools.* Palo Alto, CA: EPRI. https://www.epri.com/#/pages/product/000000003002011102/

EPRI. 2017b. *State-Level Electric Energy Efficiency Potential Estimates.* Palo Alto, CA: EPRI. https://www.energy.gov/sites/prod/files/2017/05/f34/epri_state_level_electric_energy_efficiency_potential_estimates_0.pdf

Fowler, A., H. Chong, and P. Breslin. 2018. *The Road Ahead for Zero-Emission Vehicles in California Market Trends & Policy Analysis*. San Francisco, CA: Beacon Economics for Next10. http://next10.org/sites/default/files/ca-zev-brief.pdf

Frew, B., W. Cole, Y. Sun, J. Richards, and T. Mai. 2017. *8760-Based Method for Representing Variable Generation Capacity Value in Capacity Expansion Models. Preprint.* Golden, CO: National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy17osti/68869.pdf

Gagnon, P., R. Margolis, J. Melius, C. Phillips, and R. Elmore. 2016. *Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment.* Golden, CO: National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy16osti/65298.pdf

Gagnon, P., A. Govindarajan, L. Bird, G. Barbose, N. Darghourth, and A. Mills. 2017. *Solar + Storage Synergies for Managing Commercial-Customer Demand Charges.* Berkeley, CA: Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/solar-storage-synergies-managing

Gagnon, P. B. Stoll, A. Ehlen, T. Mai, G. Barbose, A. Mills, and J. Zuboy. 2018. *Estimating the Value of Improved Distributed Photovoltaic Adoption Forecasts for Utility Resource Planning*. Golden, CO: National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/estimating-value-improved-distributed

Goldman, C., M. Reid, R. Levy, and A. Silverstein. 2010. *Coordination of Energy Efficiency and Demand Response.* Berkeley, CA: Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/coordination-energy-efficiency-and

Hampson, A. R. Tidball, M. Fucci, and R. Weston. 2016. *Combined Heat and Power Technical Potential in the United States.* Washington, D.C.: ICF International for U.S. Department of Energy. https://www.energy.gov/sites/prod/files/2016/04/f30/CHP%20Technical%20Potential%20Study%203-31-2016%20Final.pdf

Hawaiian Electric Companies. 2017. Application for Approval of Demand Response Program Portfolio Tariff Structure Revised Demand Response Portfolio. Hawaii Public Utilities Commission Docket No. 2015-0412. Filed February 10, 2017.

Hawaiian Electric Companies. 2018. Planning Hawaii's Grid for Future Generations Integrated Grid Planning Report. https://www.hawaiianelectric.com/about-us/our-commitment/investing-in-the-future/integrated-grid-planning

Hedman, B., A. Hampson, and K. Darrow. 2013. *The Opportunity for CHP in the United States.* Washington, D.C.: ICF International for American Gas Association. https://www.aga.org/sites/default/files/sites/default/files/media/the_opportunity_for_chp_in_the_united_states_-_final_report_0.pdf

Hill, D., D. Lane, K. Desrochers, F. Huessy, and R. Vandergon. 2016. *Vermont Solar Market Pathways: Becoming an Advanced Solar Economy by 2025.* Montpelier, VT: VEIC for the Department of Energy. https://www.veic.org/documents/default-source/resources/reports/vermont-solar-market-pathways-volume1-summary.pdf

Hoffman, I. G. Leventis, and C. A. Goldman. 2017. *Trends in the Program Administrator Cost of Saving Electricity for Utility Customer-Funded Energy Efficiency Programs.* Berkeley, CA: Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/trends-program-administrator-cost

Hoffman, I., C. Goldman, S. Murphy, N. Mims, G. Leventis, and L. Schwartz. 2018. *The Cost of Saving Electricity Through Energy Efficiency Programs Funded by Utility Customers: 2009–2015.* Berkeley, CA: Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/cost-saving-electricity-through/

Homer, J., A. Cooke, L. Schwartz, G. Leventis, F. Flores-Espino, and M. Coddington. 2017. *State Engagement in Electric Distribution System Planning.* Pacific Northwest National Laboratory, Lawrence Berkeley National Laboratory and National Renewable Energy Laboratory. https://emp.lbl.gov/sites/default/files/state_engagement_in_dsp_final_rev2.pdf

ICF. 2018. *Integrated Distribution Planning: Utility Practices in Hosting Capacity Analysis and Locational Value Assessment*. Washington, D.C.: ICF prepared for U.S. Department of Energy. https://gridarchitecture.pnnl.gov/media/ICF_DOE_Utility_IDP_FINAL_July_2018.pdf

IEEE Power and Energy Magazine. 2017. "Change in Brooklyn and Queens: How New York's Reforming the Energy Vision Program and Con Edison are Reshaping Electric Distribution Planning." https://ieeexplore.ieee.org/document/7866936/

IREC, Optimizing the Grid: A Regulator's Guide to Hosting Capacity Analyses for Distributed Energy Resources, https://irecusa.org/2017/12/tools-to-build-the-modern-grid/

Kramer, C., and G. Reed. 2012. *Ten Pitfalls of Potential Studies*. Montpelier, VT: Energy Futures Group for Regulatory Assistance Project. http://www.raponline.org/wp-content/uploads/2016/05/energyfutures-kramerreed-tenpitfallsesdraft2-2012-oct-24.pdf

Lazar J and Colburn, K. 2013. Recognizing the Full Value of Energy Efficiency (What's Under the Feel-Good Frosting of the World's Most Valuable Layer Cake of Benefits) Regulatory Assistance Project. September. https://www.raponline.org/event/a-layer-cake-of-benefits-recognizing-the-full-value-of-energy-efficiency/

Massachusetts Department of Energy Resources. 2016. State of Charge: Massachusetts Energy Storage Initiative. https://www.mass.gov/files/documents/2016/09/oy/state-of-charge-report.pdf

Mihlmester, P., and S. Fine. 2016. "The Locational Value of Energy Efficiency on the Distribution Grid." In *Proceedings of the 2016 ACEEE Summer Study on Energy Efficiency in Buildings* X:1-10. Washington, DC: ACEEE. https://aceee.org/files/proceedings/2016/data/papers/6_858.pdf.

Mills, A., and R. Wiser. 2014. *Strategies for Mitigating the Reduction in Economic Value of Variable Generation with Increasing Penetration Levels.* Berkeley, CA: Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/strategies-mitigating-reduction

Mills, A., and R. Wiser. 2015. *Strategies to mitigate declines in the economic value of wind and solar at high penetration in California*. Berkeley, CA: Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/strategies-mitigate-declines-economic

Mills, A., G. Barbose, J. Seel, C. Dong, T. Mai, B. Sigrin, and J. Zuboy. 2016. *Planning for a Distributed Disruption: Innovative Practices for Incorporating Distributed Solar into Utility Planning.* Berkeley, CA: Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/planning-distributed-disruption

Mims, N., T. Eckman, and C. Goldman. 2017. *Time-Varying Value of Electric Energy Efficiency.* Berkeley, CA: Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/time-varying-value-electric-energy

Myers, E. H., M. Surampudy, and A. Saxena. 2018. *Utilities and Electric Vehicles: Evolving to Unlock Grid Value*. Washington, D.C.: Smart Electric Power Alliance. https://sepapower.org/resource/utilities-electric-vehicles-evolving-unlock-grid-value/

National Action Plan for Energy Efficiency (NAPEE). 2007. *Guide for Conducting Energy Efficiency Potential Studies.* Prepared by Philip Mosenthal and Jeffrey Loiter, Optimal Energy. Washington, DC: Environmental Protection Agency. https://www.epa.gov/sites/production/files/2015-08/documents/potential_guide_0.pdf

Navigant Consulting Inc. 2016. *Benefit Cost Analysis Handbook.* New York, NY: Consolidated Edison. https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/coned-bcah.pdf?la=en

Navigant Consulting Inc. 2017. Demand Response Potential Assessment for the Hawaiian Electric Companies Supplemental Report with Modifications to the Report Filed in December 2015.

New York Department of Public Services (NY DPS). 2018. *New Efficiency New York.* Case Number 18-M-0084. April 26, 2018. https://www.nyserda.ny.gov/-/media/Files/Publications/New-Efficiency-New-York.pdf

NY DPS. 2018. Staff Whitepaper Guidance for 2018 DSIP Updates. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B3548DA1A-828E-4255-A6AF-908117A4DF1E%7D

NY DPS 2017a. Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources. Notion of Initial scopes for Phase Two Working Groups. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bED4CB1DC-2B0E-4B56-9573-79C334EAE2C9%7d

NY DPS. 2017b. Case 16-M-0411, In the Matter of Distributed System Implementation Plans. Joint Utilities Filings of Utility-Specific Implementation Matrices for Non-Wires Alternatives Suitability Criteria. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={3E7E6426-F3FC-46F3-A8C4-CD44625DA792}

NY DPS. 2017c. Case 16-M-0411, In the Matter of Distributed System Implementation Plans. Joint Utilities Supplemental Information on the Non-Wires Alternatives Identification and Sourcing Process and Notification Practices. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={5DA604B3-9CDA-45D3-8642-92A4C4171787}

Northwest Power and Conservation Council (NWPCC). 2016. Seventh Northwest Conservation and Electric Power Plan. Document 2016-2. http://www.nwcouncil.org/energy/powerplan/7/plan/

Pennsylvania Evaluation Team. 2015. Energy Efficiency Potential Study for Pennsylvania. http://www.puc.state.pa.us/Electric/pdf/Act129/SWE_EE_Potential_Study-No_Appendices.pdf

Potter, J., E. Stuart, and P. Cappers. 2018. *Barriers and Opportunities to Broader Adoption of Integrated Demand Side Management at Electric Utilities: A Scoping Study.* Berkeley, CA: Lawrence Berkeley National Lab. https://emp.lbl.gov/publications/barriers-and-opportunities-broader.

Puget Sound Energy (PSE). 2016. 2017 IRP Demand Side Resource Conservation Potential Assessment Report. Bellevue, WA: Prepared by Navigant for Puget Sound Energy. https://pse.com/aboutpse/EnergySupply/.../DSR-Conservation-Potential-Assessment.pdf

Puget Sound Energy. 2017. Integrated Resource Plan. Bellevue, WA: Puget Sound Energy. https://pse.com/aboutpse/EnergySupply/Documents/8a_2017_PSE_IRP_Chapter_book_compressed_110717.pdf

Rohmund, I., and B. Kester. *Energy Efficiency Potential Study for the State of New Mexico.* 2011. Walnut Creek, CA: Global Energy Partners and The Brattle Group for New Mexico Energy, Minerals and Natural Resources Department's Energy, Conservation and Management Division. http://www.emnrd.state.nm.us/ECMD/Multimedia/documents/StateofNewMexicoEEPotentialStudy_Vol1ExecSummary.pdf

Rohmund, I., B. Kester, and F. Nguyen. *State of Hawaii Energy Efficiency Potential Study Final.* 2014. Walnut Creek, CA: EnerNoc Utility Solutions for Hawaii Public Utility Commission. http://puc.hawaii.gov/wp-content/uploads/2013/04/State_of_HI_Potential_Study_Final.pdf

Rohmund, I., K. Kolnowski, D. Costernaro, V. Nielsen, A. Faruqui, R. Hledik, A. Gunn, and W. Davis. 2017. *PacifiCorp Demand-Side Resource Potential Assessment for 2017-2036 Volume 5*. Walnut Creek, CA: Applied Energy Group. http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Demand_Side_Management/2017_DSM_Potential_Study/PacifiCorp_DSM_Potential_Vol5_Class13_Appendix_FINAL_2017-02-14.pdf

Rylander, M., L. Rogers, and J. Smith. *Distribution Feeder Hosting Capacity: What Mattes When Planning for DERs?* 2015. Palo Alto, California: Electric Power Research Institute. https://www.epri.com/#/pages/product/000000003002004777/

Schellenberg, Josh A., and Michael J. Sullivan. "Electric Vehicle Forecast for a Large West Coast Utility." *2011 IEEE Power and Energy Society General Meeting*, 2011, doi:10.1109/pes.2011.6039026. https://ieeexplore.ieee.org/document/6039026/

Schwartz, L., and N. Mims. March 13, 2018. "Overview of Integrated Distributed Planning Concepts and State Activity." Berkeley, CA: Berkeley Lab. Presentation to Mid-Atlantic Distributed Resources Initiative. https://emp.lbl.gov/publications/overview-integrated-distribution

Schwartz et al. 2018a. *Distribution Systems and Planning Training for Western States.* https://emp.lbl.gov/publications/distribution-systems-and-planning

Schwartz, L. June 24, 2018b. "PUC Distribution Planning Practices." Berkeley, CA: Berkeley Lab. Presentation to National Association of State Utility Consumer Advocates. http://nasuca.org/nwp/wp-content/uploads/2017/08/Schwartz-NASUCA-PUC-planning-practices-20180624.pdf

Sierzchula, William, et al. "The Influence of Financial Incentives and Other Socio-Economic Factors on Electric Vehicle Adoption." *Energy Policy*, vol. 68, 2014, 183–194. doi:10.1016/j.enpol.2014.01.043. https://www.sciencedirect.com/science/article/pii/S0301421514000822

Spurr, M., A. Sampson, and J. Wang. 2014. *Assessment of Technical and Economic Potential for CHP in Minnesota.* Prepared for Minnesota Department of Commerce, Division of Energy Resources. Minneapolis, MN: FVB Energy and ICF International. http://mn.gov/commerce-stat/pdfs/chp-technical-economic-potential.pdf

Tang, Y., J. S. Homer, T. E. McDermott, M. H. Coddington, B. Sigrin, and B. A. Mather. 2017. *Summary of Electric Distribution System Analyses with a Focus on DERs.* Richland, WA: Pacific Northwest National Laboratory and National Renewable Energy Laboratory. https://epe.pnnl.gov/pdfs/Summary_of_electric_distribution_system_analyses_April_10_FINAL.pdf

Washington Utilities and Transportation Commission. 2017a. *Draft Report and Policy Statement on Treatment of Energy Storage Technologies in Integrated Resource Planning and Resource Acquisition*. Dockets UE-151069 and U-161024, March 6, 2017. Olympia, Washington. Accessed August 24, 2017, at https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=67&year=2015&docketNumber=151069.

Washington Utilities and Transportation Commission. 2017b. *Report on Current Practices in Distributed Energy Resource Planning.* Olympia, WA: Washington State Legislature. https://www.utc.wa.gov/aboutUs/Documents/DER%20Planning%20Report%20-%20Final.pdf

Woolf, T., C. Neme, M. Kushler, S. Schiller, T. Eckman, and J. Michals. 2017. *National Standard Practice Manual for Assessing Cost Effectiveness of Energy Efficiency Resources.* https://nationalefficiencyscreening.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf

Appendix A. Additional Resources

DER Modeling Resources

- California Public Utilities Commission. *Guide to Production Cost Modeling in the IRP Proceeding.* http://cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442455821
- Electric Power Research Institute. *Stochastic Analysis to Determine Feeder Hosting Capacity for Distributed Solar PV.* https://www.epri.com/#/pages/product/1026640/
- National Renewable Energy Lab. *Electricity Capacity Expansion Modeling, Analysis and Visualization: A Summary of Selected High-Renewable Modeling Experiences.* https://www.nrel.gov/docs/fy16osti/64831.pdf
- National Renewable Energy Lab. *Capacity Expansion Modeling for Storage Technologies.* https://www.nrel.gov/docs/fy17osti/67532.pdf
- California Public Utilities Commission. *Electric Production Cost Modeling.* http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/PCM%20Aug1_fth_v7(1).pdf
- Midwest Independent System Operator. *Electric Production Cost Modeling.* http://home.eng.iastate.edu/~jdm/ee590-Old/ProductionCostModleFundamentals_EE590.pdf
- National Renewable Energy Lab. *Analysis of Modeling Assumptions used in Production Cost Models for Renewable Integration Studies.* https://www.nrel.gov/docs/fy16osti/65383.pdf
- National Renewable Energy Lab. Distributed Generation Market Demand Model. https://www.nrel.gov/analysis/dgen/
- National Renewable Energy Lab. Regional Energy Deployment System Model (Capacity expansion model). https://www.nrel.gov/analysis/reeds/model-capabilities.html
- National Renewable Energy Lab. 8760-Based Method for Representing Variable Generation Capacity Value in Capacity Expansion Models. https://www.nrel.gov/docs/fy17osti/68869.pdf
- National Renewable Energy Lab. *SMARtDaTa: Standardized multi-scale Models of Anonymized Realistic Distribution and Transmission data.* https://arpa-e.energy.gov/?q=slick-sheet-project/smartdata-grid-models

Distributed Solar Potential, Forecasting and Modeling

- National Renewable Energy Lab. *Treatment of Solar Generation in Electric Utility Resource Planning*. October 2013. http://my.solarroadmap.com/userfiles/Solar-Generation-in-Utility-Resource-Planning.pdf
- Berkeley Lab. *Planning for a Distributed Disruption: Innovative Practices for Incorporating Distributed Solar into Utility Planning.* August 2016. https://emp.lbl.gov/publications/planning-distributed-disruption

Demand Response Potential, Forecasting and Modeling

- Bonneville Power Administration. *BPA Distributed Energy Resource Benchmarking Report.* https://www.bpa.gov/EE/Technology/demand-response/Documents/2016_DERBenchmarkReport.pdf

- Lawrence Berkeley National Lab. *Analytical Frameworks to Incorporate Demand Response into Long-term Resource Planning.* https://emp.lbl.gov/publications/analytical-frameworks-incorporate

Electric Vehicles Potential, Forecasting and Modeling

- Navigant for the California Energy Commission. *2016 Electric Vehicle Geographic Forecast Methodology.* https://efiling.energy.ca.gov/GetDocument.aspx?tn=220516
- Berkeley Lab. 2013. *Los Angeles Air Force Base Vehicle to Grid and Building Integration Project*, https://building-microgrid.lbl.gov/projects/los-angeles-air-force-base-vehicle-grid

Energy Efficiency Potential, Forecasting and Modeling

- Energy Futures Group for NEEP, Energy Efficiency as a T&D Resource. *Lessons from Recent U.S. Efforts to Use Geographically Targeted Energy Efficiency Programs to Defer T&D Investments.* http://www.neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf
- National Renewable Energy Lab. Energy Efficiency Potential in the US Single Family Housing Sector. https://www.nrel.gov/docs/fy18osti/68670.pdf
- ICF International. The Locational Value of Energy Efficiency on the Distribution Grid. https://aceee.org/files/proceedings/2016/data/papers/6_858.pdf

Hosting Capacity Analysis and DERs

- Electric Policy Research Institute. *Distribution Feeder Hosting Capacity: What Matters When Planning for DER?* https://www.epri.com/#/pages/product/000000003002004777/
- Minnesota Hosting Capacity Analysis (forthcoming). https://ccaps.umn.edu/documents/CPE-Conferences/MIPSYCON-PowerPoints/2017/UIFDERHostingCapacityAnalysis.pdf
- National Renewable Energy Lab: Technologies to Increase PV Hosting Capacity in Distribution Feeders https://www.nrel.gov/docs/fy16osti/65995.pdf

Load Forecasting and DERs

- Interstate Renewable Energy Council. "Cornerstone for Next Generation Grid Activities: Forecasting DER Growth." https://irecusa.org/2018/02/cornerstone-for-next-generation-grid-activities-forecasting-der-growth/
- Lawrence Berkeley National Lab. *Load Forecasting in Electric Utility Integrated Resource Planning.* https://emp.lbl.gov/publications/load-forecasting-electric-utility
- National Association of Regulatory Utility Commissioners. *EISPC Load Forecasting Case Study.* https://pubs.naruc.org/pub.cfm?id=536E10A7-2354-D714-5191-A8AAFE45D626
- Mills, A. "Forecasting load on the distribution and transmission system with distributed energy resources." Presentation for Distribution Systems and Planning Training for Midwest Public Utility Commissions, Minneapolis, MN. January 17, 2018. http://eta-publications.lbl.gov/sites/default/files/10._mills_forecasting_load_with_ders.pdf

Resource Planning and DERs

- Lawrence Berkeley National Lab. *Impacts of Variable Renewable Energy on Bulk Power System Assets, Pricing and Costs.* https://emp.lbl.gov/publications/impacts-variable-renewable-energy
- Kahrl, F., A. D. Mills, L. Lavin, N. Ryan, A. Olsen, and L. Schwartz (technical editor). 2016. *The Future of Electricity Resource Planning*. Berkeley, CA: Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/future-electricity-resource-planning
- Lamont, D., and J. Gerhard. 2013. *The Treatment of Energy Efficiency in Integrated Resource Plans: A Review of Six State Practices.* Montpelier, VT: Regulatory Assistance Project. https://www.raponline.org/wp-content/uploads/2016/05/rap-lamont-gerhard-treatementofeeinirp-2013-jan-28.pdf

Appendix B. Examples of a Level One Analysis

Many reports, studies and other resources are available on a range of topics related to integrating DERs (see Appendix B). Here, we discuss examples of the range of available studies specifically related to DER potential.[116] These studies fall into a Level One analysis based on the framework presented in this guide, and have been included as an appendix so as to allow the body of the guide to focus on the *integrated* analysis of DERs.

Most of those studies offer a single resource potential assessment with little, if any, interaction among the DERs considered. Often, the assessment results are specific to a particular state policy (e.g., an energy efficiency potential study for required utility customer-funded, DSM portfolio planning).

Generally, these studies address one or more of the following types of DER potential:[117]

- *Technical* – All of the resource that is technologically feasible
- *Economic* – The portion of the resource that is cost-effective, based on a defined set of cost and benefit criteria
- *Achievable* – The portion of the resource that is cost-effective and realistically obtainable, recognizing adoption/market barriers (e.g., high, medium and low achievable potential)
- *Program* – The portion of the resource resulting from a given set of programs and funding that is realistically achievable

Following is a summary of selected DER potential studies, by resource, identifying one or all of these types of potential depending on the goal of the analysis. The selected studies illustrate national and state level potential studies, as well as a range of approaches or methodologies. Chapter 6 provides examples of studies that evaluate two or more DERs in an integrated way. Appendix A lists additional resources by topic area.

Combined Heat and Power

Combined Heat and Power Technical Potential in the United States (2016), by ICF for DOE, estimated the technical potential for each state for three types of combined heat and power markets: (1) topping cycle, (2) waste heat to power (bottoming cycle), and (3) district energy.[118] The study found that "a significant portion of the remaining technical potential for on-site CHP in the U.S. is located in commercial facilities."[119] The report estimated 240 GW of technical potential for combined heat and power nationwide, with approximately 30 percent of the potential in commercial facilities. Table A-1 displays the potential by state. The top three states for CHP potential are Texas, California and Illinois,

[116] Berkeley Lab offers these studies only as examples and not as an endorsement of their methodologies or their conclusions.
[117] NAPEE (2007).
[118] Hampson et al. (2016).
[119] Hampson et al. (2016), iii.

and the top three sources of potential are chemicals, commercial office buildings, and colleges/universities.

The study provides detailed combined heat and power potential for each state, including amount of combined heat and power installed, types of industries with combined heat and power, potential by industry and capacity size, and number of sites. While the study does not consider any other DERs, it can be used as a resource by states as a starting point when considering a more detailed analysis of combined heat and power potential, or when considering how to analyze combined heat and power and other DERs together. Additional assumptions would be necessary to calculate economic or achievable potential.

Table A-1. Total U.S. combined heat and power technical potential for all states

State	Total On-site Potential (MW)	Total Export Potential (MW)	Total CHP Technical Potential	State	Total On-site Potential (MW)	Total Export Potential (MW)	Total CHP Technical Potential
Alabama	2,777	1,001	3,777	Montana	377	441	818
Alaska	408	242	650	Nebraska	984	520	1,504
Arizona	2,320	533	2,853	Nevada	1,254	360	1,614
Arkansas	1,795	892	2,686	New Hampshire	447	136	584
California	11,542	7,280	18,822	New Jersey	3,761	1,674	5,435
Colorado	1,665	433	2,098	New Mexico	1,140	457	1,597
Connecticut	1,214	455	1,670	New York	6,908	5,559	12,466
Delaware	747	786	1,533	North Carolina	4,352	1,164	5,516
District of Columbia	762	146	908	North Dakota	445	417	862
Florida	6,917	1,484	8,401	Ohio	7,005	4,082	11,087
Georgia	5,110	2,355	7,464	Oklahoma	1,805	1,387	3,192
Hawaii	563	237	799	Oregon	1,337	816	2,153
Idaho	659	304	962	Pennsylvania	7,025	3,872	10,896
Illinois	7,161	5,664	12,825	Rhode Island	616	180	796
Indiana	4,145	2,084	6,229	South Carolina	3,063	1,536	4,599
Iowa	1,993	1,675	3,668	South Dakota	378	222	600
Kansas	1,909	1,007	2,916	Tennessee	3,981	3,005	6,986
Kentucky	2,721	1,796	4,517	Texas	13,675	12,151	25,826
Louisiana	4,903	7,074	11,977	Utah	1,119	416	1,535
Maine	494	250	743	Vermont	228	153	381
Maryland	2,282	809	3,091	Virginia	4,308	1,633	5,941
Massachusetts	3,028	1,040	4,068	Washington	2,387	1,971	4,357
Michigan	4,291	2,021	6,312	West Virginia	929	449	1,378
Minnesota	3,260	3,671	6,931	Wisconsin	3,187	2,622	5,809
Mississippi	1,833	1,512	3,345	Wyoming	847	254	1,101
Missouri	2,882	1,482	4,364	Total	148,936	91,709	240,644

U.S. DOE CHP Deployment Program, 2016.

An earlier national combined heat and power assessment by ICF, in 2013, calculated economic potential based on state average electric and natural gas rates and typical CHP equipment cost and performance characteristics.[120] ICF estimated 6,355 MW of combined heat and power available with a payback of less than five years, and 35,257 MW with a payback of five to 10 years. While the analysis is dated, the report provides a methodology that could be applied to understand the customer's perspective on economic potential on a state by state basis using the 2016 U.S. Department of Energy combined heat and power technical potential study.[121] ICF considered the impact of capital cost reductions, increases in electricity costs, and decreases in natural gas prices on combined heat and power economic potential. States may need to refine ICF's approach and use industry-specific prices instead of average electric and gas rates and consider state financial incentives for combined heat and power.

---

[120] Hedman, Hampson, and Darrow (2013).

[121] Hampson et al. (2016).

ICF also conducted a statewide combined heat and power technical and economic potential study for Minnesota in 2014.[122] The study identified combined heat and power technical and economic potential by utility service territory and application. The study used a simple payback analysis derived from Minnesota-specific electricity and natural gas retail rates and representative combined heat and power equipment and performance characteristics to calculate economic potential. The economic potential results were grouped into three payback categories: (1) strong, less than five-year payback; (2) moderate, 5- to 10-year payback; and (3) minimal, greater than 10-year payback. ICF estimated that 213 MW of combined heat and power could be implemented in 2030, and 252 MW in 2040 (referred to as the *base case*). ICF also considered several policy options (incentives, use of utility Weighted Average Cost of Capital, use of biofuel, Alternative Portfolio Standard) and found the policies could increase combined heat and power adoption 100–840 MW beyond the base case in 2030.

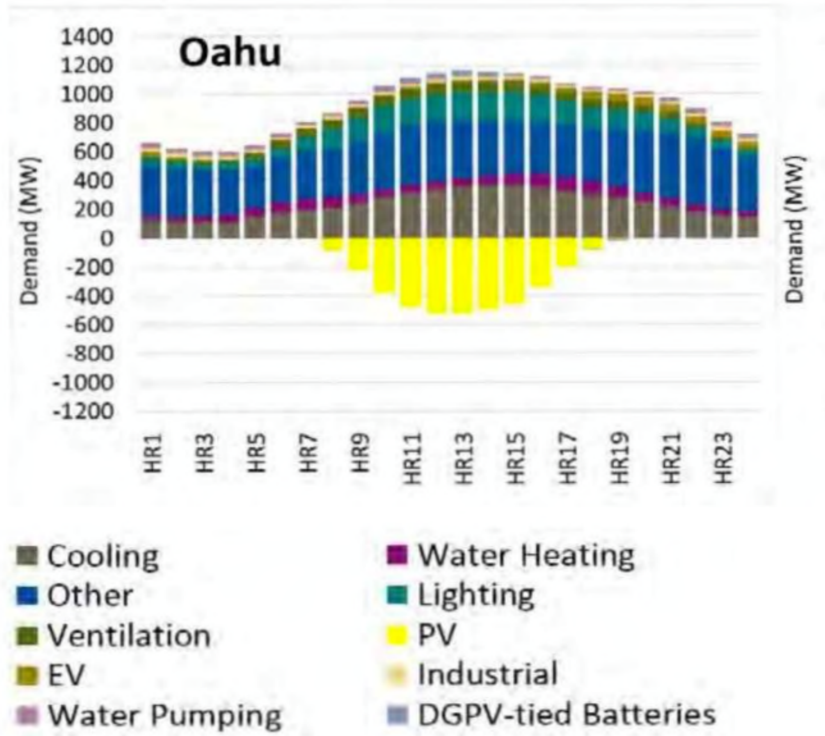
Demand Response

Hawaiian Electric Companies (Hawaiian Electric Company, Hawaii Electric Light Company, and Maui Electric Company) contracted Navigant in 2016 to conduct a demand response potential study based on hourly load profiles by customer class, building type, and end use, including distributed solar.[123] The study is unique because of the granularity of the base forecast. For the base forecast, the utility made a number of assumptions regarding adoption to determine storage and battery forecasts, stand-alone battery forecasts, distributed solar annual hourly production, and electric vehicle charging. The base forecast also considered a variety of efficiency and demand response measures, including cooling, water heating, ventilation and lighting. Figure A-1 displays the components and resource timing of the base forecast.

[122] Spurr, Sampson, and Wang (2014).

[123] Hawaiian Electric Companies (2017).

Figure A-1. Projected baseline load profiles by end use for an average September 2025 weekday



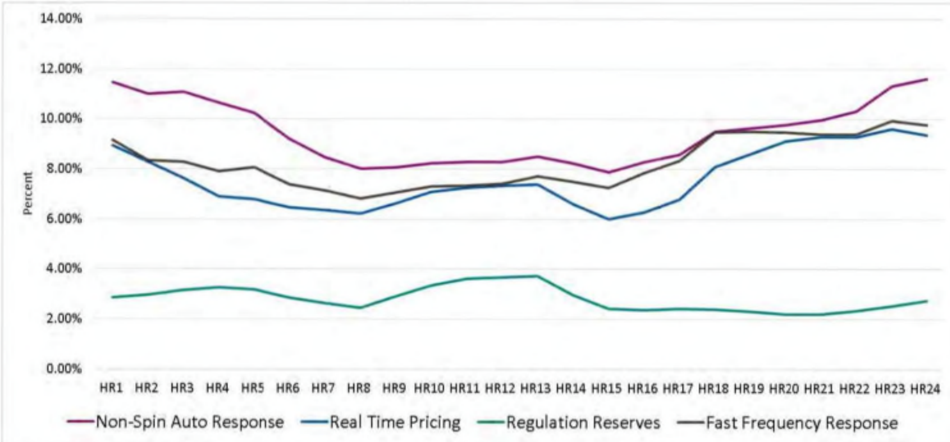
The load profiles also included batteries tied to distributed solar and stand-alone batteries. In evaluating the potential for demand response, Navigant created two flexible demand response types to better estimate participation. The identified participating load was multiplied by the amount of load that can be increased or decreased for demand response grid services (e.g., fast frequency response,[124] regulating reserves,[125] non-spin auto response[126]) or in response to real time pricing for the demand response potential. Figure A-2 shows the demand response potential in 2025 in Oahu for these three grid services and real time pricing. Navigant found that non-spin auto response demand response had the highest load reduction potential, followed by fast frequency response and real time pricing.

[124] "Fast frequency response programs compensate customers for providing a load-reducing response following a contingency scenario (e.g., a generation trip)." Hawaiian Electric Companies (2017), 9.

[125] Regulating resource programs help the utility balance their electric grids by operating DR resources in response to automatic generation control signals from the Energy Management System." Hawaiian Electric Companies (2017), 9.

[126] Non-spin auto response is also referred to as replacement reserves, which are "off-line, quick start resources that can be used as a replacement reserve provided they can be started and synchronized to the grid before the limited 10-minute or 30-minute duration resource expires." Hawaiian Electric Companies (2017), 9.

Figure A-2. Oahu load reduction potential results by demand response option for an average 2025 September weekday (percent of gross load)



PacifiCorp Demand-Side Resource Potential Assessment for 2017–2036 (Volume 5) considers load management and rate structures in a potential assessment (two types of demand response). "The first step in conducting an integrated assessment of Class 1 [load management] and Class 3 [retail rate] DSM resources is to define a hierarchy of options, according to which eligibility criteria are established. This is necessary to account for the interactive effects between Class 1 and Class 3 DSM resources, and to avoid double counting of impacts."[127] Figure A-3 displays the order in which Class 1 and Class 3 demand-side management resources are included in the demand-side management model for the assessment.

Figure A-3. PacifiCorp participation hierarchy for Class 1 and Class 3 demand-side management options

Table F-1 *Participation Hierarchy in Class 1 and 3 DSM Options by Customer Class*

	Program Option	Resource Class	Residential	Small C&I	Medium C&I	Large C&I	Extra Large C&I	Irrigation
Loaded First	DLC Central AC	Class 1	x	x	x			
	DLC Space Heating	Class 1	x	x	x			
	DLC Water Heating	Class 1	x	x	x			
	DLC Smart Thermostats	Class 1	x					
	DLC Smart Appliances	Class 1	x					
	DLC Room AC	Class 1	x					
	DLC Irrigation	Class 1						x
	Ice Energy Storage	Class 1		x	x			
	Curtail Agreements	Class 1				x	x	
	TOU Demand Rate	Class 3	x					
	TOU Demand Rate w EV	Class 3	x					
	Time-Of-Use	Class 3	x	x	x	x	x	x
	Critical Peak Pricing	Class 3	x	x	x	x	x	x
	Real Time Pricing	Class 3				x	x	
Loaded Last	DLC Elec Vehicle Charging	Class 1	x					

[127] Rohmund et al. (2017), F-2.

Electric Vehicles

Several robust potential studies estimate electric vehicle penetration for a state or utility service territory, including studies which focus on the customer behavior and incentive programs.[128]

Published in 2013, *Review of Hybrid, Plug-in Hybrid, and Electric Vehicle Market Modeling* summarizes the major methods used to forecast EV deployment and reviews the advantages and disadvantages of each method.[129] The report focused on agent-based behavior models, consumer choice models and market diffusion models and found there is high variability within and among methods used to forecast electric vehicle deployment. The variances stem from differences among the methods, values of input parameters, assumptions, and forecasted market and policy conditions. The agent-based models discussed in the paper estimated plug-in hybrid electric vehicle (PHEV) sales would remain minimal without subsidies and tax exemptions. However, with subsidies and tax exemptions, one of the agent-based models estimated that PHEV sales could grow to be between 4 to 5 percent of yearly sales in 2020 and 17 to 24 percent of yearly sales in 2040. The consumer choice models expressed even higher variability between hybrid electric vehicle (HEV) and PHEV estimates due to different assumptions about subsidies, tax credits and gasoline process. The consumer choice models estimated HEV sales could range between 8 to 90 percent of yearly sales in 2020 and 18 to 64 percent of yearly sales in 2040. The consumer choice models estimated that PHEV sales could range between 1 to 18 percent of yearly sales in 2020 and 9 to 18 percent of yearly sales in 2040. There are fewer market diffusion models, and they project their sales differently. In the models presented, the highest assessment estimated that HEV sales could grow to be a little less than two million a year in 2020. The diffusion models estimated that PEV sales would be, at maximum, one million sales per year in 2020 and six million sales per year in 2035.

The Influence of Financial Incentives and Other Socio-Economic Factors on Electric Vehicle Adoption[130] discussed the impact public policy, financial incentives, and other socioeconomic factors have on electric vehicle adoption. The study found that electric vehicle charging infrastructure is the best predictor for electric vehicle adoption, and that broad sociodemographic variables, such as education level and income, were less useful predictors. Figure A-4 shows the number of charging stations and corresponding EV market share for 30 countries in 2012. Figure A-5 shows the financial incentives and EV market share of the same 30 countries in 2012. Both financial incentives and charging infrastructure have a positive correlation with EV adoption, but the correlation is strongest with charging infrastructure. This study demonstrates that while financial incentives are important, charging infrastructure can be more important to spur EV adoption.

[128] Schellenberg and Sullivan (2011); Fowler et al. (2018); Myers Surampudy, and Saxena (2018).
[129] Al-Alawi and Bradley (2013).
[130] Sierzchula et al. (2014).

Figure A-4. National charging infrastructure by country and corresponding EV market share for 2012[131]

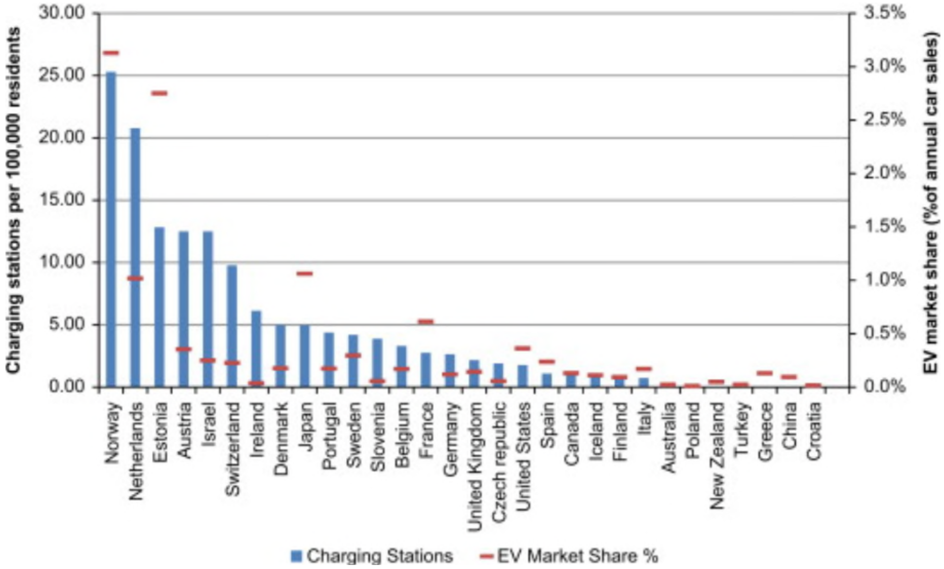
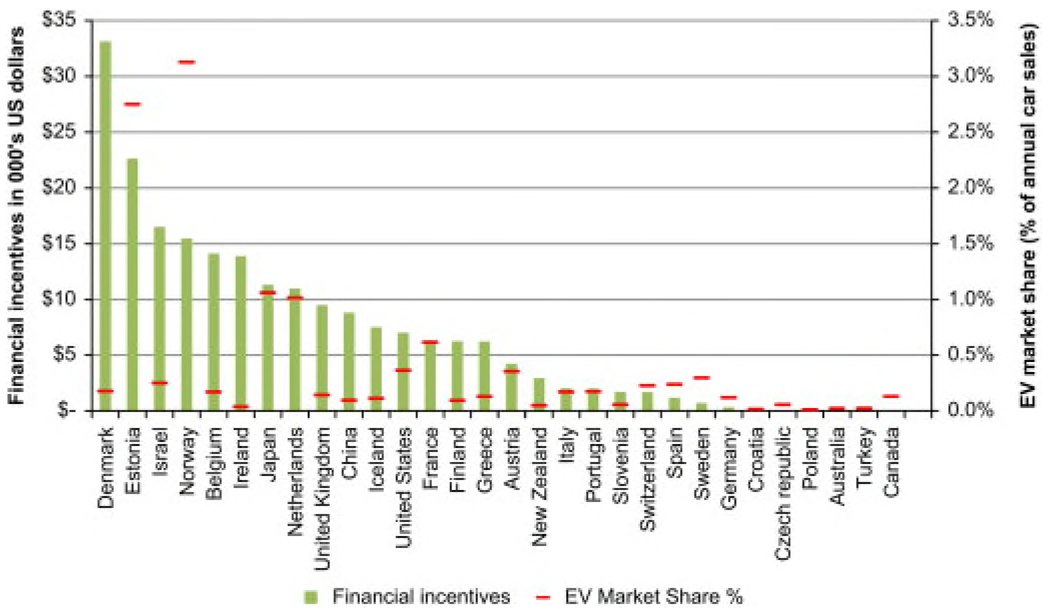


Figure A-5. Financial incentives by country and corresponding EV market share for 2012[132]



The California Energy Commission (CEC) staff has conducted extensive work to consider the integration of DERs, including electric vehicles, in their *2017 Integrated Energy Policy Report* (IEPR).[133] To meet that state's goal of deploying 4.2 million zero-emission vehicles by 2030, and ensure there are adequate energy resources, the CEC developed a transportation energy demand forecast in the IEPR.

---

[131] Sierzchula et al. (2014).
[132] Sierzchula et al. (2014).
[133] CEC Staff (2017).

The demand forecast includes detailed surveys about consumer preferences and modeling about the growth of electric vehicles. The consumer preferences survey revealed a growing preference for zero emission vehicles and the importance of vehicle range.

The CEC addressed the challenges of electric vehicle adoption by creating a range of scenarios to better understand the factors driving adoption and how electric vehicle forecasts might differ based on input assumptions. The CEC estimated that the plug-in electric vehicle (PEV) stock in California would be between 2.6 million and 5.9 million by 2030. Table A-2 summarizes the inputs and assumptions for each electric vehicle scenario and how they arrived at that range of PEV stock. The electric vehicle scenarios presented by the CEC can help other states and utilities understand sensitivities of electric vehicle forecasts and make more educated input assumptions.

Table A-2. Summary of inputs and assumptions of CEC's electric vehicle scenarios[134]

PEV SCENARIOS					
INPUTS	**LOW**	**MID**	**HIGH**	**AGGRESSIVE**	**BOOKEND**
PREFERENCES					
Consumers' PEV Preference	Constant at 2017 Level	Increase with PEV Market Growth	Increase with PEV Market Growth	Increase with PEV Market Growth	Increase with PEV Market Growth
INCENTIVES					
Federal Tax Credit	Eliminated after 2019	Decreasing starting 2019	Decreasing starting 2019	Constant through 2030	Constant through 2030
State Rebate	To 2020	To 2025	To 2025	To 2030	To 2030
HOV Lane Access	To 2021	To 2025	To 2025	To 2025 for PHEV / 2030 for EV	To 2025 for PHEV / 2030 for EV
ATTRIBUTES					
Availability of PEVs (in 2030)	PEV models available in 11 of 15 CEC LDV classes	PEV models available in 11 of 15 CEC LDV classes	PEV models available in 11 of 15 CEC LDV classes	PEV models available in 13 of 15 CEC LDV classes	PEV models available in all CEC LDV classes
Vehicle / Battery Price (by 2030)	PEV prices based on battery price declining to ~$120/kWh	PEV prices based on battery price declining to ~$100/kWh	PEV prices based on battery price declining to ~$89/kWh	PEV prices based on battery price declining to ~$73/kWh	PEV prices reach parity with gasoline vehicles
Avg. Range (2030)	~230 miles	~230 miles	~270 miles	~270 miles	~270 miles
Refuel Time (2030)	15 -21 min	15 -21 min	10-16 min	10-16 min	Same as gasoline
Time to Station (2030)	7-8 min	Same as gasoline	Same as gasoline	Same as gasoline	Same as gasoline by 2025
FORECAST RESULT					
PEV STOCK in 2030	2.6 mil	3.3 mil	3.9 mil	5.3 mil	5.9 mil

Source: California Energy Commission

The Road Ahead for Zero-Emission Vehicles in California: Market Trends & Policy Analysis provides major trends and factors influencing and driving EV adoption in the state. While focused on California, the report may be helpful to other states that are conducting an electric vehicle potential study to understand the latest factors influencing electric vehicle adoption, including changes internationally.[135] The study covers a myriad of factors from total cost of ownership, price, and EV model options to discussion of the importance of charging infrastructure and the effect of various public policies.

[134] CEC Staff (2017).
[135] Fowler et al. (2018).

The study *Electric Vehicle Forecast for a Large West Coast Utility*[136] used a replicable methodology to forecast electric vehicle adoption in a utility service territory and determine the effect various policies could have on that forecast. The 2011 study forecasted that for one Western U.S. utility, battery electric vehicles (BEVs) would reach 2 percent market penetration, PHEVs would reach 10 percent market penetration, and HEVs would reach 21 percent market penetration in 2018 without any incentive being offered to the customer.[137] The paper went a step further and tested a variety of incentives a utility might offer to see what effect that would have on adoption propensities. Installing free charging stations had the biggest effect on adoption propensity, increasing the probability of PHEV or BEV purchase to 46 percent. Receiving stickers that allow drivers to drive in the high occupancy vehicle (HOV) lane had the smallest effect on adoption propensity, increasing the probability of purchase 6 percent. Table A-3 summarizes the various incentives they tested and their effect on adoption propensity. The study also forecasted that partial hybrid electric vehicles will have much higher adoption rates than battery electric vehicles, which effects the kind of charging infrastructure a utility might implement or support.

Table A-3. Impact of utility incentives and information programs on purchase probabilities[138]

Utility Incentive / Information Program	Impact on purchase probability of:	
	PHEV	BEV
Free charging station installation	46.7%	45.8%
$1,000 utility rebate	16.8%	16.7%
Free electricity for a year	14.7%	14.6%
HOV sticker	6.6%	6.3%
Additional information on EVs	17.8%	-18.8%
Additional information on charging stations	14.2%	52.1%

Finally, *Utilities and Electric Vehicles: Evolving to Unlock Grid Value* focuses on how utilities are handling the rise in electric vehicle adoption.[139] Approximately 75 percent of the utilities surveyed for the study are in the early stages of electric vehicle adoption, focusing on educating customers and utility staff, with few external-facing electric vehicle activities. The few utilities that were further along, with EV pilots or full scale EV programs, were mainly investor-owned utilities. The report can be very helpful for utilities and regulators trying to understand the current landscape of utility-led EV programs. Georgia Power, Maui Electric, Austin Energy, San Diego Gas and Electric, and New Hampshire Electric Cooperative were a few of the utilities identified to be further along with EV adoption, and are great examples for other utilities looking for lessons learned to build out their own EV programs. The report

[136] Schellenberg and Sullivan (2011).
[137] Schellenberg and Sullivan (2011).
[138] Schellenberg and Sullivan (2011).
[139] Myers et al. (2018).

also focuses on the utility EV regulatory landscape. They found that the most common regulatory findings were about special rates for EVs, charging infrastructure and customer engagement efforts. There is also discussion in the report about the role utilities can play in EV roll-out, and it discusses how some of the major state regulatory findings have concluded. For example, in California, utilities have been allowed to help scale EV adoption by being charging-station providers, but in Missouri Ameren was denied the right to install DC fast charging units.

Energy Efficiency[140]

There are many energy efficiency potential studies for U.S. utilities, states and regions that are publicly available.[141] It is common for these assessments to include technical, economic and achievable potential.

The Northwest Power and Conservation Council is a national leader in estimating energy efficiency potential. In the *Seventh Northwest Conservation and Electric Power Plan* (Seventh Power Plan), the Council developed conservation supply curves based on the amount and shape of efficiency available at a variety of cost groupings, by year.[142] The energy efficiency "supply curves" served as an input to the larger regional planning model for optimization with all other resources. As an alternative to forecasting customer efficiency adoption rates, the Council assumes that over a 20-year planning period, 85 percent of the technical potential of energy efficiency can be acquired through ratepayer-funded programs and improved codes and standards in the region.[143] In the *Seventh Power Plan*, the Council found that energy efficiency alone could cost-effectively meet all load growth in 90 percent of the 800 future conditions evaluated. In the *Eighth Power Plan*, the Council will be looking at the reliability of capacity-saving estimates from efficiency, among other refinements.

Another example of an energy efficiency potential study that includes conservation supply curves is Puget Sound Energy's (PSE's) *2017 IRP Demand-Side Resource Conservation Potential Assessment Report*.[144] The utility uses these supply curves as an input to its integrated resource planning process.[145] The report is unique because it disaggregated the achievable technical energy and peak demand potential to the ZIP-code level for the utility's service territory.

---

[140] The U.S. EPA National Action Plan for Energy Efficiency created a *Guide for Conducting Energy Efficiency Potential Studies* that provides information on identifying the need, purpose, type of study, data, methods, uses and contracting guidance for energy efficiency potential studies. NAPEE (2007).

[141] See the DOE Energy Efficiency Potential Catalog at https://www.energy.gov/eere/slsc/energy-efficiency-potential-studies-catalog.

[142] Northwest Power and Conservation Council (2016).

[143] The Council conducted a 20-year retrospective review of energy efficiency development in the region which verified this planning assumption. See: *Achievable Savings – A Retrospective Look At The Council's Conservation Planning Assumptions*. August 2007. https://www.nwcouncil.org/reports/2007/2007-13.

[144] PSE (2017)

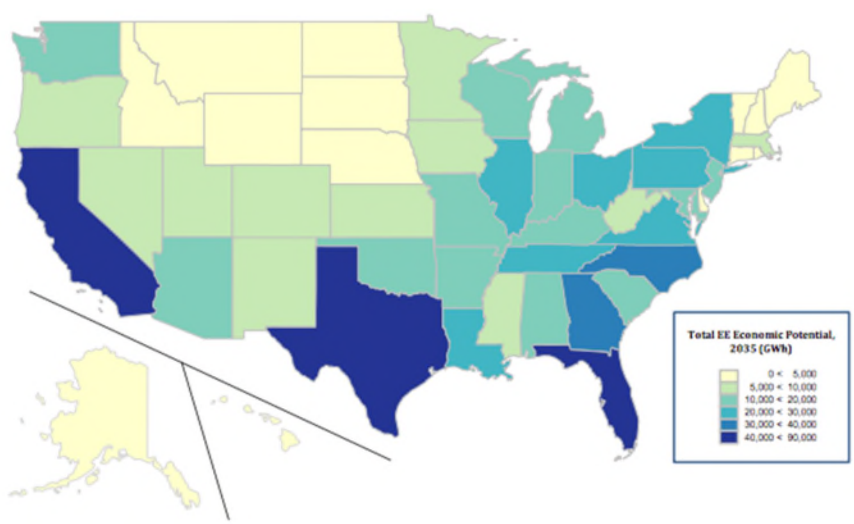
[145] PSE (2016).

One of the factors that distinguishes the Council's and PSE's approaches to estimating energy efficiency potential from most others is that the determination of economic potential is done by directly competing energy efficiency and demand response against supply-side resources in capacity expansion models. This process allows the cost-effectiveness of these DERs to be determined dynamically by the models, rather than through the use of an avoided cost that is derived independently of the potential impact of efficiency and demand response on the timing and magnitude future resource needs.

The California Public Utilities Commission commissioned a robust statewide efficiency potential study, *Energy Efficiency Potential and Goals Study for 2018 and Beyond,* to develop both individual utility and statewide energy efficiency goals.[146] The study modeled five scenarios to explore how energy efficiency potential might change based on changing assumptions about policies, measures and market response. A distinctive feature of the study is its use of various assumptions to calculate the potential from particular savings sources (e.g., technologies receiving a utility rebate, whole building packages, industrial custom measures and emerging technologies, behavior, retrocommissioning, operation efficiency, residential low income, codes and standards, and financing).

The Electric Power Research Institute (EPRI) updated its national economic energy efficiency potential study in May 2017 on a state-by-state basis.[147] EPRI used regional avoided costs to determine if energy efficiency measures were cost-effective under the Total Resource Cost test. Figure A-6 shows the calculated energy efficiency potential by state.

Figure A-6. Total economic potential of energy efficiency (EE) in 2035, EPRI[148]



---

[146] CPUC (2017).

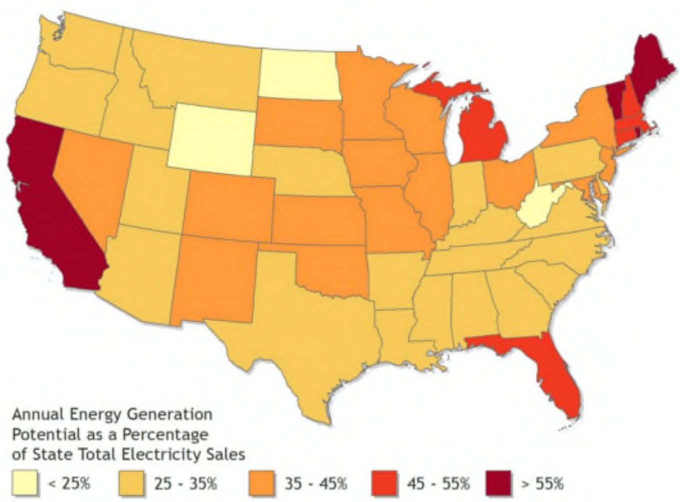
[147] EPRI (2017b).

[148] It is worth noting that while larger states have greater energy efficiency potential due to larger populations, EPRI did not determine the potential as a percent of retail sales or some other normalized economic potential value.

Solar

The National Renewable Energy Laboratory (NREL) published a rooftop solar technical potential assessment for the U.S. in 2016.[149] The report provides the potential at the national, state, and ZIP-code level based on light detection and ranging data, geographic information system (GIS) data, and solar generation modeling. The study used three primary methods to determine solar photovoltaic potential: (1) constant-value methods, (2) manual selection, and (3) GIS-based methods. Technical potential was provided by building class (small, medium, large) and by state. Figure A-7 shows the annual solar energy generation potential by state.

Figure A-7. Annual rooftop solar energy generation technical potential as a percentage of state total electricity sales



NREL also provides state solar forecasts in its Annual Technology Baseline and Standards Scenario.[150] The report has an online Standard Scenarios Results Viewer that allows the user to designate the year, choose from preselected scenarios, and view the results by resource.[151] Solar forecasts can also be purchased from vendors.[152,153]

Storage

The State of Charge: Massachusetts Energy Storage Initiative (September 2016) analyzed the application of storage technologies (e.g., batteries, flywheel, compressed air and pumped hydro storage) statewide.[154] The report considered the location of energy storage (transmission, distribution, and behind the meter applications), the optimal size of storage technologies to achieve maximum

---

149 Gagnon et al. (2016).

150 Cole et al. (2017).

151 Standard Scenarios Results Viewer. https://openei.org/apps/reeds/

152 gtmresearch. U.S. Solar Market Insight. https://www.greentechmedia.com/research/subscription/u-s-solar-market-insight#gs.v8j2xfc; BloombergNEF. New Energy Outlook 2018. https://about.bnef.com/new-energy-outlook/

153 BloombergNEF. New Energy Outlook 2018. https://about.bnef.com/new-energy-outlook/

154 Massachusetts Department of Energy Resources (2016).

benefit to ratepayers, and the reduction in greenhouse gas emissions that can be achieved with optimal energy storage. The report concluded that energy storage can create over $2.2 billion in electric system benefits in Massachusetts. To recognize the electric system benefits, the report also investigated use cases that "illustrate how storage owners and developers can capture value from owning, operating, or contracting for services from energy storage resources." The use cases informed policy and program recommendations to increase energy storage in the state, which included grant and rebate programs, storage in state portfolio standards, establishing or clarifying regulatory treatment of utility storage, and statutory changes to allow storage in clean energy procurements.[155]

In 2016, Navigant evaluated the potential for storage in PacifiCorp's six-state territory as part of the company's 2017 IRP.[156] The report examined drivers and challenges to the energy storage market in the utility's territory but did not determine the technical or economic potential for storage. The evaluation qualitatively considered current and future applications of paired resources: nonresidential solar, residential solar, wind, hydro, and combined heat and power, each combined with storage.

The Navigant report also assessed the technical and market potential for solar, small wind and hydro, combined heat and power with reciprocating engines, and combined heat and power with micro turbines to support PacifiCorp's 2017 IRP by projecting customer adoption of these resources over the next 20 years. The projected impact of these resources was applied as a reduction to the forecasted load in the IRP. The study did not evaluate resources in an integrated fashion. Navigant used simple payback as a key indicator for customer uptake and included all federal, state and utility incentives in the payback calculation. Adoption was considered under multiple scenarios (base, high and low cases).

[155] Massachusetts Department of Energy Resources (2016).
[156] Corfee, Goffri and Romano (2016).