Chapter 7. Electric Utility Policies

States are adopting new or modifying existing utility policies in order to enable greater investment in energy efficiency, renewable energy, and combined heat and power (CHP). State public utility commissions (PUCs) are aligning electricity resource planning and ratemaking processes to encourage utilities to fully incorporate these resource options into their infrastructure investment and operational decisions. PUCs are also modifying customer electricity rates and interconnection standards to support greater investment by families and businesses in energy efficiency, distributed renewable energy, and CHP. States are also providing policy direction to ensure that new electric grid investments are made and deployed in a manner that maximizes energy efficiency and renewable energy.

This chapter focuses on the authorities that state legislatures have granted to PUCs to regulate electricity rates and reliability, as these authorities directly affect utilities' and customers' investments in energy efficiency, renewable energy, and CHP. Other state agencies, such as air offices, energy offices, and consumer advocates, can work with their PUCs to provide collaborative input and/or formally intervene during policy design and implementation. Some of the policies in this chapter could also apply to municipally and cooperatively owned utilities—which are not subject to PUC regulation in most states—to the extent that states, elected officials, and local boards can direct or encourage these utilities to take action. For more context, see the overview of the U.S. electricity system later in this chapter.

State Policy Options in the *Guide to Action*

Type of Policy	For More Information
Funding	
Funding and Financial Incentive Policies	Chapter 3
Energy Efficiency Policies	
Energy Efficiency Resource Standards	Section 4.1
Energy Efficiency Programs	Section 4.2
Building Codes for Energy Efficiency	Section 4.3
State Appliance Efficiency Standards	Section 4.4
Lead by Example	Section 4.5
Renewable Portfolio Standards	
Renewable Portfolio Standards	Chapter 5
Combined Heat and Power	
Policy Considerations for Combined Heat and Power	Chapter 6
Electric Utility Policies	
Electricity Resource Planning and Procurement	Section 7.1
Policies That Sustain Utility Financial Health	Section 7.2
Interconnection and Net Metering Standards	Section 7.3
Customer Rates and Data Access	Section 7.4
Maximizing Grid Investments to Achieve Energy Efficiency and Improve Renewable Energy Integration	Section 7.5

Table 7.1 lists examples of states that have implemented policies to incentivize energy efficiency, renewable energy, and CHP through electricity resource planning, ratemaking, terms of service, and direct grid investment. States can refer to this table to identify other states they may want to contact for additional information about their clean energy policies or programs. The *For More Information* column lists the *Guide to Action* section where each in-depth policy description is located.

In addition to the five policy areas covered by this chapter, states are adopting many other policies that maximize the benefits of energy efficiency, renewable energy, and CHP through utility policy approaches. These additional policies are addressed in other chapters of the *Guide to Action* as follows:

- "Funding and Financial Incentive Policies" describes additional ways states provide funding for clean energy supply through grants, loans, tax incentives, and other funding mechanisms (see Chapter 3).
- "Energy Efficiency Policies" presents policies that states have adopted to support cost-effective energy efficiency programs by removing key market, regulatory, and institutional barriers (see Chapter 4).
- "Renewable Portfolio Standards" describes how some states are requiring electric utilities and other retail electric providers to supply a specified minimum percentage (or absolute amount) of customer load with eligible sources of renewable electricity (see Chapter 5).
- "Policy Considerations for Combined Heat and Power" highlights policy options that states are using to capture the environmental, energy, economic, and reliability benefits of CHP technologies (see Chapter 6).

Table 7.1: Electric Utility Policy Options for Supporting Energy Efficiency, Renewable Energy, and CHP

Policy	Description	State Examples	For More Information
Electricity Resource Planning and Procurement	Many states require electric utilities to engage in resource planning through integrated resource planning, pre-approval of large capital investments, and resource procurement processes. These policies provide a mechanism for utilities, regulators, and other stakeholders to assess the long-term costs, benefits, and risks of existing and new supply- and demand-side resources. They also create a more level playing field for energy efficiency, renewable energy, and CHP.	CT, GA, NJ, NV, OR	Section 7.1
Policies That Sustain Utility Financial Health	Traditional regulatory approaches discourage investment in cost-effective demand-side resources that reduce sales. State PUCs can encourage energy efficiency, distributed renewable generation, and CHP by decoupling profits from sales volumes, enabling program cost recovery, and providing performance incentives.	AZ, CA, NV, NY	Section 7.2
Interconnection and Net Metering Standards	Interconnection and net metering rules play a critical role in promoting clean distributed generation (DG) systems such as renewable energy and CHP. Interconnection rules establish system requirements and application procedures, while net metering policies allow DG systems to receive credit for electricity generated on site that is exported to the grid. States can develop interconnection policies and net metering standards that remove barriers and facilitate clean DG.	MA, OR, UT	Section 7.3
Customer Rates and Data Access	Utility rates and other charges can influence the economic attractiveness of energy efficiency, distributed renewables, and CHP. Some rate structures have greater potential for clean energy benefits than others. Providing customers with access to energy usage data can serve a complementary role by helping them make informed and efficient decisions about their energy use.	CA, CT, GA, HI, IL, NY	Section 7.4
Maximizing Grid Investments to Achieve Energy Efficiency and Improve Renewable Energy Integration	States can take steps to ensure that new investments in electricity distribution infrastructure are planned and operated in a manner that increases energy efficiency and enables high penetrations of renewable energy.	CA, IN, MA, MD, Pacific Northwest	Section 7.5

Overview of the U.S. Electricity System

To understand how these electric utility policies work, it helps to understand the U.S. electric power grid and the roles that states play. As the diagram on page 7-6 shows, the power grid is a complex, interconnected system. Most of the nation's electricity is generated at centralized power plants, transmitted over long distances through high-voltage transmission lines (sometimes across multiple states), and then delivered through local distribution wires to residential, commercial, and industrial end-users.

The system must generate enough electricity supply to meet demand from all end-users and deliver supply through a network of transmission and distribution lines. This balancing act takes place in real time, as the grid is limited in its ability to store excess power for later use. Maintaining this balance is challenging because the need for electric services is dynamic, with demand fluctuating depending on the season, the time, and the weather. Supply may also fluctuate based on operating conditions, as well as on weather conditions and time of day for renewable sources such as solar and wind.

Many companies and other organizations play a role in generating and delivering electricity. These entities are subject to regulations and oversight at the state, regional, and federal levels. States vary in their authorities over the types of power plants and delivery infrastructure that utilities build and maintain, as well as the terms of service for and rates charged by the utilities that deliver power to customers. Regional balancing authorities coordinate the transmission of electricity across states. In some areas of the country, this coordination takes place through organizations known as independent system operators (ISOs) or regional transmission organizations (RTOs). The Federal Energy Regulatory Commission (FERC)[52] approves the RTO/ISO market rules and recognizes the North American Electric Reliability Corporation (NERC)[53] as the national Electric Reliability Organization.

At the distribution system level, where electricity is delivered to retail customers, utility ownership type and state regulatory structure varies. About 75 percent of the nation's electricity is delivered by investor-owned utilities (IOUs)—which are for-profit corporations—or other private entities (Figure 7.1). The remaining electricity is delivered to customers by cooperatively owned utilities; utilities owned by local governments; and other publicly owned entities, including those owned by the federal government. For example, the Tennessee Valley Authority—a federally owned utility—generates electricity that it sells to certain large customers and other utilities. Similarly, four federal Power Marketing Administrations (PMAs) sell electricity generated by federally owned and operated hydroelectric dams in 33 states to other utilities and a few large customers.[54] Figure 7.1 shows how the prevalence of different types of utilities varies by state.

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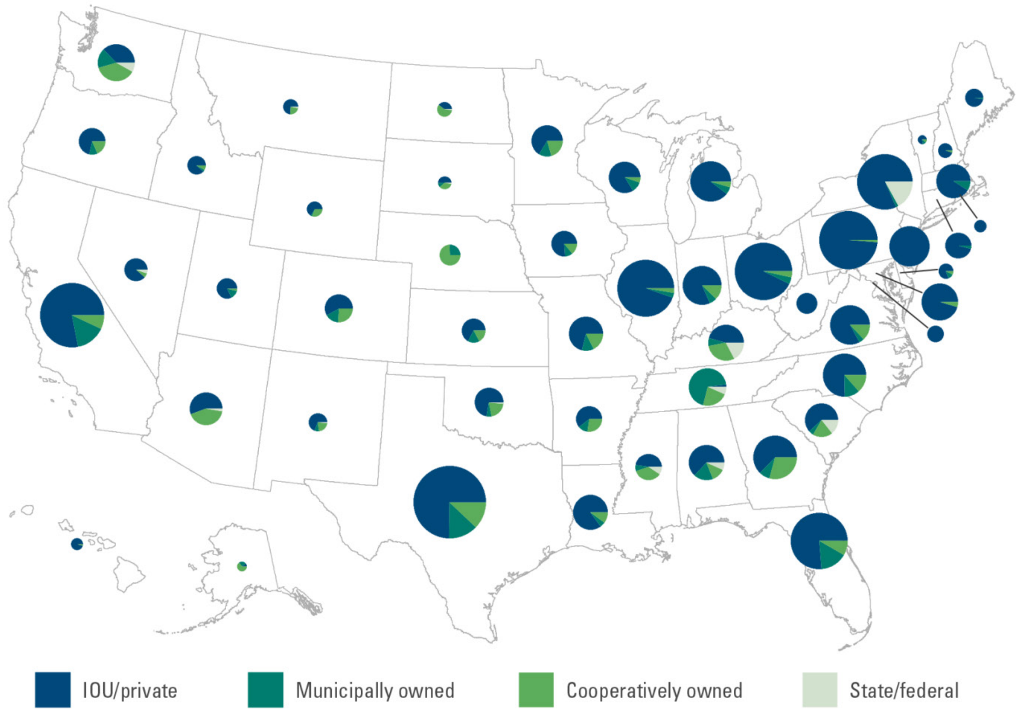
[52] Visit http://www.ferc.gov for more information about FERC's roles and responsibilities.

[53] Visit http://www.nerc.com for more information about NERC and its eight regional entities.

[54] Visit http://www.eia.gov/todayinenergy/detail.cfm?id=11651 for more information about the four federal PMAs.

Figure 7.1: Share of Electricity Delivered to Customers by Utility Ownership Type, 2012



"IOU/private" includes IOUs, retail power marketers, and unregulated utilities. "Cooperatively and municipally owned" includes utilities classified as "cooperative" or "political subdivision."

Source: U.S. Energy Information Administration, Annual Electric Power Industry Report, Form 861, 2012 data.

Role of State Public Utility Commissions

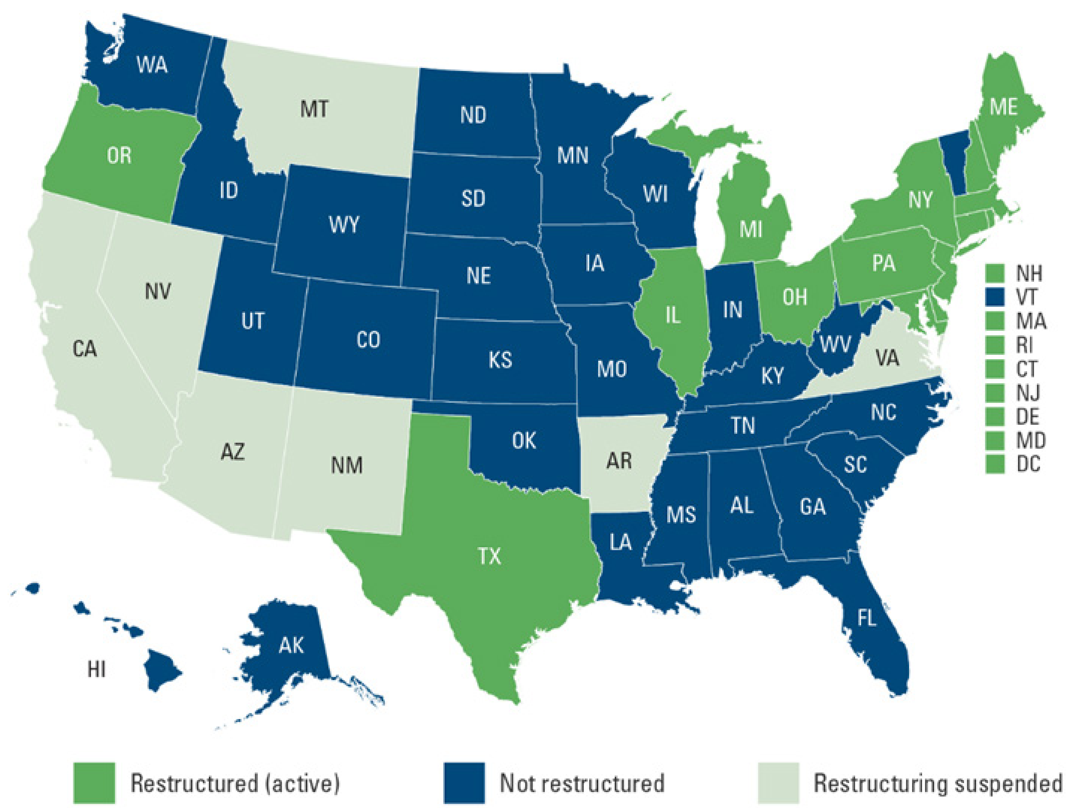
PUCs typically have authority over planning, ratemaking, and terms of service, which can all affect deployment of energy efficiency, renewable energy, and CHP. PUC processes vary by state, according to the authorities granted to them by the state legislature. The regulatory structure for the electricity market is a key difference across states. PUCs have traditionally regulated IOUs that generate, transmit, and distribute electricity. However, in the mid-1990s, some states restructured their electricity markets (also referred to as deregulated or retail choice states), which means that electricity generation may be owned and operated by independent power producers, with the PUC regulating the distribution service that is still provided by IOUs. Figure 7.2 shows these states. Although customers can purchase electricity from competitive suppliers in restructured states, PUCs still approve the rates the IOUs may charge for delivering the electricity to customers, as well as the electricity supply rates for those customers who do not purchase electricity from competitive suppliers.

Utility Costs and Revenues: A Bird's-Eye View

Electric utilities' costs fall into two main categories: *fixed costs*, such as infrastructure, and *variable costs*, such as the fuel used to generate electricity. Utilities recover these costs and earn money through the rates they charge to their customers. Some utilities earn a portion of their revenue through fixed charges, such as flat monthly service fees, but utilities typically earn most of their revenue through variable charges—that is, a charge per kilowatt-hour of electricity delivered. If a utility relies on volumetric charges to pay for a substantial portion of its fixed costs, as is often the case, the utility will have an incentive to increase electricity sales instead of decreasing them (e.g., by investing in energy efficiency). Section 7.2 discusses state policies that sustain utility financial health while increasing investment in energy efficiency, distributed renewable energy, and CHP.

PUCs typically have less authority over publicly and cooperatively owned utilities, though some states do regulate their rates to customers and oversee their electricity resource planning processes. For example, TVA has little to no direct state oversight, but the utility transmits electricity supply to 155 local distribution utilities that are subject to state requirements. Although municipally and cooperatively owned utilities may not be subject to the same PUC regulations as IOUs, they are overseen by elected local officials and/or boards of directors that require some form of public disclosure of the utility's performance and investment decisions.

Figure 7.2: Electricity Market Regulatory Structure by State



Source: U.S. Energy Information Administration, http://www.eia.gov/electricity/policies/restructuring/restructure_elect.html. Status as of April 2015.

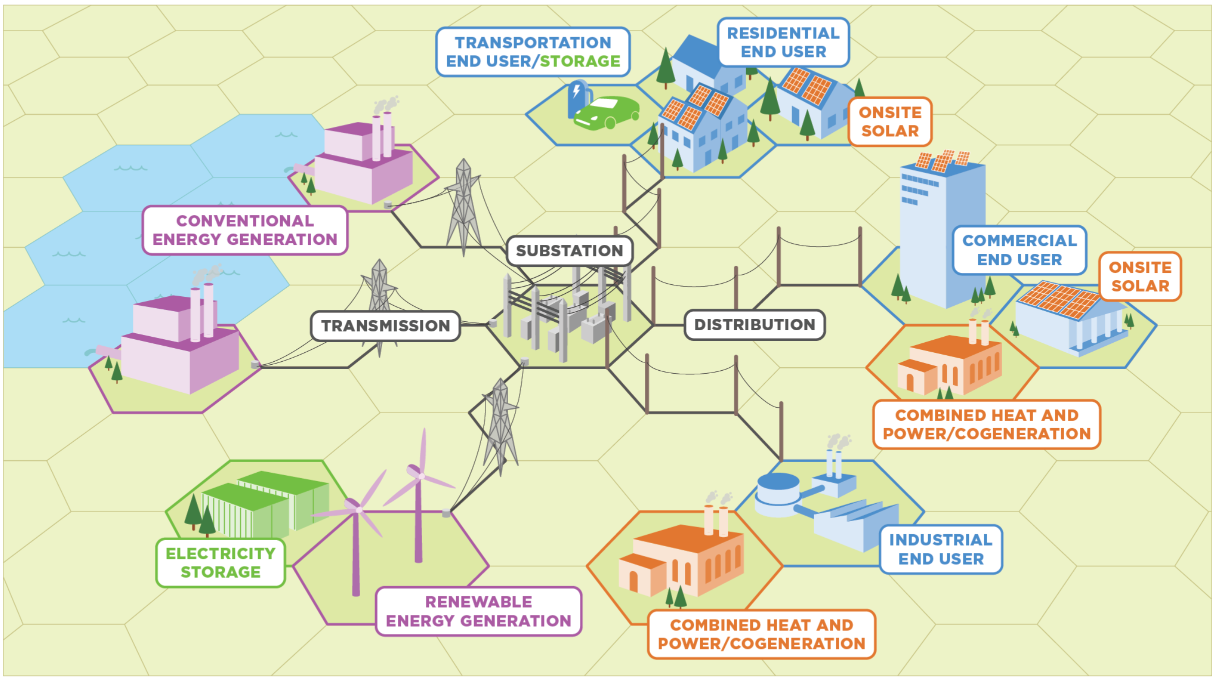
Role of State Environmental Agencies

Regardless of utility ownership and electricity market structure, state air agencies and other environmental regulators have authority over the electric power sector because of its substantial environmental impacts. The carbon dioxide emitted from generating electricity accounts for about one-third of all the nation's greenhouse gas emissions—more than any other activity. Most of the United States' electricity is generated by burning fossil fuels, which also emits other forms of air pollution that contribute to environmental problems such as acid precipitation, regional haze, and smog. Electric power generation can also require large quantities of water for cooling, discharge warmer water into local water bodies, and produce waste.[55]

[55] For more information on the environmental impact of electricity generation, see www.epa.gov/energy.

Figure 7.3: A Quick Guide to the U.S. Electric Power Grid: How Electricity Is Generated and Delivered to Customers

The U.S. electricity system is a complex network of power plants, transmission and distribution lines, and end-users of electricity. This system is called the **electric power grid**.



CENTRALIZED GENERATION

The United States generates most of its electricity at centralized power plants, which are usually located away from end-users. In 2013, most U.S. electricity generation came from **conventional sources**, including coal, natural gas, and other fossil fuels (67%), and nuclear power (19%). **Renewable sources** include hydroelectricity (7%) and wind and solar (6%). Large wind and solar installations are considered centralized generation, and their share of total generation is projected to increase.

DISTRIBUTED GENERATION

Distributed generation refers to technologies that generate electricity at or near where it will be used, such as **onsite solar panels**, **combined heat and power**, and diesel generators. Distributed generation may serve a single structure, such as a home or business, or be part of a system such as a microgrid at an industrial complex, military base, or college campus. When connected to the grid, onsite solar and combined heat and power have the potential to support delivery of clean, reliable power to additional customers and to reduce electricity losses along transmission and distribution lines. Distributed sources produce far less electricity than centralized power plants, but their use is growing.

STORAGE

Thermal and electricity storage technologies can be used to improve reliability, save excess power for when it is needed, and reduce costs. Though not widespread today, storage options are increasingly being used to support renewable energy generation. Electric vehicles may be used for storage if they charge when power demand from the rest of the grid is low (e.g., at night) and feed power back into the grid when demand is high.

DELIVERY

Once electricity is generated at a centralized power plant, it travels long distances through a series of interconnected high-voltage **transmission** lines. **Substations** "step-down" high-voltage power to a lower voltage, sending the lower voltage electricity to consumers through a network of **distribution** lines.

END-USERS AND ENERGY EFFICIENCY

U.S. electricity use is approximately evenly split among **residential**, **commercial**, and **industrial** customers. The **transportation** sector accounts for a small fraction of electricity use, though this may increase due to electric vehicles. End-users can meet some of their needs by adopting energy-efficient technologies and practices. In this respect, energy efficiency is a resource that reduces the need to generate electricity.

7.1 Electricity Resource Planning and Procurement

Policy Description and Objective

Summary

> As part of electricity resource planning, utilities compare options for meeting customer demand for electricity services. Electricity resource planning includes power plants, electricity delivery, and end-use demand.

Most states require utilities to engage in a form of electricity resource planning to substantiate that the utility's plans for meeting demand for electricity services are in the public interest. Planning processes vary greatly across states, but are most commonly accomplished through processes that consider costs, benefits, and risks over the long term, including integrated resource planning or integrated resource plans (IRP) and power plant investment preapprovals through a Certificate of Public Convenience and Necessity (CPCN).[56]

State public utility commissions (PUCs) include electricity resource planning as part of docketed proceedings[57] that encourage public involvement and transparency. The PUC's role is to review and evaluate plans, and its goals include providing reliable, least cost electricity service to customers. Incorporating energy efficiency, renewable energy, and combined heat and power (CHP) in electricity resource planning is consistent with these goals.

Electricity resource planning decisions are typically long-term in nature, having implications for decades. Effective planning and procurement policies may help parties evaluate the impact of market changes and regulations on existing and new electricity resources, and mitigate short-term cost fluctuations by developing robust and diverse resource portfolios that include energy efficiency, renewable energy, and CHP.

For utilities that own and operate electricity generation, transmission, and distribution, resource planning may be part of both IRP and planning for discrete resource approvals (such as through CPCN). For load-serving utilities in restructured electricity markets, resource planning also informs how these utilities procure electricity supply for default customers (i.e., those who do not purchase electricity from competitive electricity suppliers). For more information on electric utility ownership and electricity market structures, see the electricity grid overview provided in the introduction to Chapter 7.

A successful electricity resource planning approach typically includes:

- Rigorous and meaningful participation of diverse stakeholders, including the utility, utility regulators, consumer advocates, and environmental advocates.
- Development and vetting of key analysis factors, such as demand forecasts, commodity price forecasts, and available resource options.

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[56] The CPCN dates back to the 1870s and is a legal term that applies to regulatory regimes governing public service industries (Jones 1979). While most states continue to call this legal process "CPCN," some use the abbreviation "CCN" and others use a different name altogether. In Minnesota, for example, the process is referred to as Advance Determination of Prudence and in Vermont it is referred to as Certificate of Public Good.

[57] Here, a docketed proceeding refers to the process through which a utility formally files a request or a proposed plan with the state PUC. The PUC reviews the submission and ultimately makes a final determination. When the initial submission is filed, the PUC opens a docket where the initial filing and subsequent stakeholder comments, amendments, revisions, and decisions are stored. PUCs typically make these dockets accessible to the public electronically.

- Use and vetting of one or more correctly scaled and structured electricity system models.

This chapter discusses several policy options to encourage decision-makers to consider all resources in electricity resource planning. The information presented about these policies and their implications is based on the experiences and best practices of states that have implemented planning policies, as well as other sources, including local, regional, and federal agencies and organizations; research foundations and nonprofit organizations; universities; and utilities (SEE Action 2011; Synapse 2013; Tellus 2010).

Objective

Most states require electric utilities to engage in transparent and public planning processes to achieve a mix of energy resources that cost-effectively and reliably meet customers' demand for electricity service in the near- and long-term with due consideration for state priorities and risk. Given the economic, environmental, and other benefits of energy efficiency, renewable energy, and CHP, states are adopting specific policies to encourage utilities to more fully incorporate these resources into their plans. Utilities have expertise in electricity resource planning, but other stakeholder perspectives are also useful to ensure that broader public interests are served.

Benefits

By adopting policies to fully integrating energy efficiency, renewable energy, and CHP into electricity resource planning, states help ensure that utilities consider a broad range of electricity resource options and avoid investment in more expensive electricity supply or delivery infrastructure that may not be consistent with state objectives for least cost and reliable electricity service. In addition, increasing the penetration of low- or no-emission resources may reduce the cost to comply with existing and future environmental regulations. Utilities, their customers, and the public benefit from a more diverse resource mix that leverages the multiple benefits of energy efficiency, renewable energy, and CHP (see Chapter 1, "Introduction and Background"). They also benefit from greater certainty that utility regulators will allow the recovery of costs from investing in energy efficiency, renewable energy, and CHP.[58]

Background on State Electricity Resource Planning

States use rate case proceedings to set electricity rates that allow utilities to recover costs, such as fuel procurement, operational, maintenance, and capital expenses. In a traditional rate case, a utility must prove that investments and commitments made on behalf of ratepayers were reasonable. The utility must also consider any resource portfolio or performance standards that the state might have in place (see p. 7-7-20 for additional discussion). Electricity resource planning and resource procurement processes are designed to mitigate the utilities' risk of planning imprudence; share information; and offer regulators, consumers, and other stakeholders an opportunity to influence utility decisions.

From the late 1980s through the mid-1990s, IRP processes were common in the electric industry. With vertically integrated[59] electric utilities responsible for generation, transmission, and distribution services for their customers, integrated resource planning was a useful tool for developing the most efficient resource

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[58] Cost recovery is determined in separate proceedings that typically allow cost recovery when a utility's investment decisions are demonstrated to be in the public interest (usually least cost/least risk).

[59] Vertical integration refers to a situation where the same entity (a utility) owns and operates generating units (power plants), transmission lines, and distribution of electricity to customers. Some states and utilities still largely follow this model, while others have decoupled generation, transmission, and distribution through restructuring. See the introduction to Chapter 7, "Electric Utility Policies," for more discussion about various types of utilities and market structures.

portfolio. In 1992, 36 states had IRP requirements in place. After electricity market restructuring, the prevalence of ratepayer-funded energy efficiency programs declined significantly as the focus of resource planning shifted to short-term commitments. States either rescinded their IRP regulations or ceased requiring utilities to comply with them. However, many states are returning to IRP processes as a tool to ensure a variety of public goals.

Today, most states require one or more forms of electricity resource planning. Planning requirements differ significantly from state to state, and even within a state. Some regulations require that utilities use distinct methods of analysis or consider specific resources in planning. To the extent that utilities must create more than one resource plan in the same state in order to comply with separate regulations, they may have different processes for creating those plans, and thus they may arrive at significantly different conclusions, despite being governed by the same regulators. The varying definitions of electricity resource planning processes generally fall into four categories: IRP, discrete resource approvals through CPCN, default service (also referred to as Standard Offer Service), and long-term procurement planning (LTPP). Table 7.1.1 summarizes these policies, and Table 7.1.2 identifies which policies are in place in each state. Descriptions of each policy follow. Some of these policies are specific to either regulated or restructured (sometimes called deregulated) states; see the introduction to Chapter 7 for an overview of these concepts.

Table 7.1.1: Electricity Resource Planning and Procurement Strategies at a Glance

Strategy	Overview	Applicability	Legal Status
Integrated Resource Planning	Integrated resources planning results in utility plans for meeting forecasted annual peak and energy demand through a portfolio of supply-side and demand-side resources over a specified future period.	With some exceptions, IRP rules typically apply to generation and transmission owners in regulated states.	State PUCs conduct a formal review of IRPs, but these reviews are generally not legally binding.
Discrete Resource Approvals Through a CPCN	A CPCN is a docketed proceeding before a state utility commission in which a utility provides justification for a large capital investment in generation or transmission infrastructure.	A CPCN is required for owners of generation and transmission projects. It occurs in both regulated and restructured states, as required by state law.	A CPCN proceeding is a litigated process. An approval gives permission, but does not require, a utility to take the requested action.
Default Service	Default service provisions—also known as Standard Offer Service—ensure that load-serving utilities procure electricity for those customers who have not elected to choose a competitive energy provider.	Default service applies to distribution-only utilities operating in restructured states.	Procurement of electricity for default service customers is required by law.
LTPP	LTPP refers to utility plans that solicit market-based supply offers over a shorter time period than traditional IRPs.	LTPP applies to distribution-only utilities operating in restructured states.	In states where it occurs, LTPP is required by law.

Table 7.1.2: States with Electricity Resource Planning Processes, as of December 2014

State	Integrated Resource Planning	Discrete Resource Approvals Through a CPCN	Default Service	LTPP
Alabama	a	✓		
Alaska	b			
Arizona	✓			
Arkansas	✓	✓		
California			✓	✓
Colorado	✓	✓		
Connecticut	✓		✓	✓
Delaware	✓		✓	
District of Columbia			✓	
Florida		✓		✓c
Georgia	✓	✓		
Hawaii	✓			
Idaho	✓			
Illinois	✓		✓	✓
Indiana	✓	✓		
Iowa	✓d			
Kansas		✓		
Kentucky	✓	✓		
Louisiana	✓	e		
Maine			✓	
Maryland		✓	✓	
Massachusetts			✓	✓
Michigan	✓		✓	✓
Minnesota	✓	✓		
Mississippi	✓	✓		
Missouri	✓			
Montana	✓			
Nebraska	✓			
Nevada	✓	✓		
New Hampshire	✓		✓	
New Jersey			✓	
New Mexico	✓	✓		
New York			✓	
North Carolina	✓	✓		
North Dakota	✓	✓		
Ohio			✓	
Oklahoma	✓	f		
Oregon	✓		✓	
Pennsylvania			✓	
Rhode Island			✓	
South Carolina	✓			
South Dakota	✓			
Tennessee	g			

Table 7.1.2: States with Electricity Resource Planning Processes, as of December 2014

State	Integrated Resource Planning	Discrete Resource Approvals Through a CPCN	Default Service	LTPP
Texas			✓	✓
Utah	✓	h		
Vermont	✓	✓		i
Virginia	✓			
Washington	✓			
West Virginia		✓		
Wisconsin		✓		
Wyoming	✓	✓		

Note: Planning requirements vary by state.

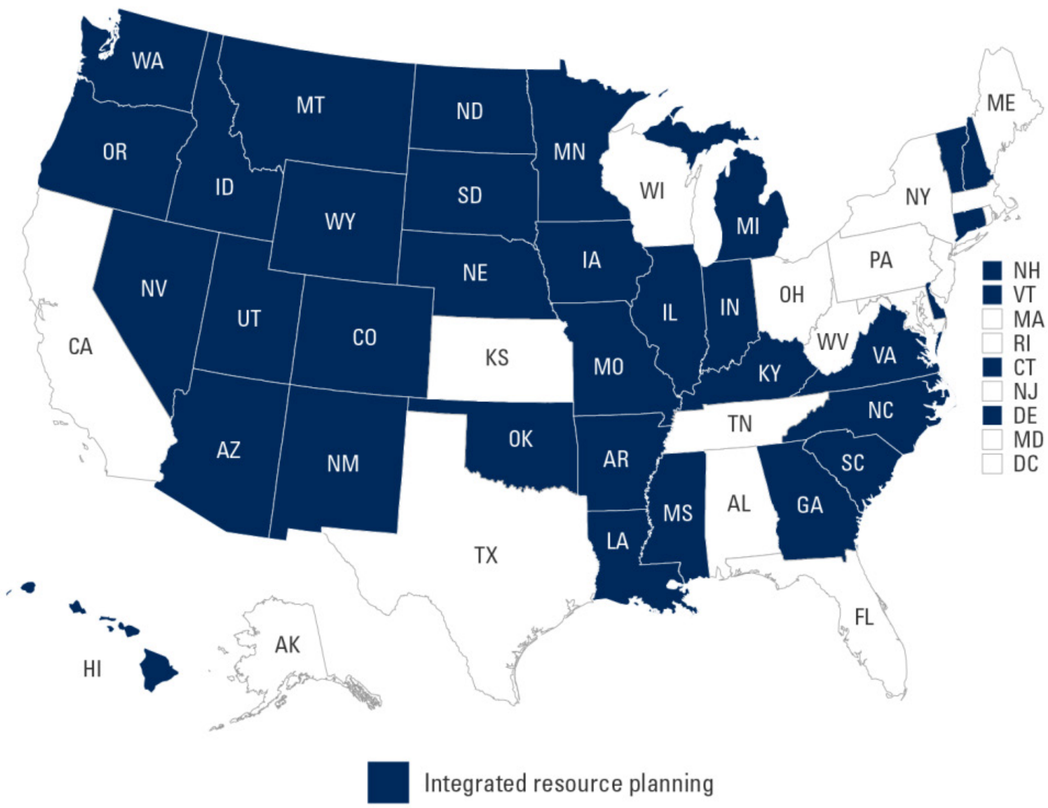
a As a subsidiary of the Southern Company, Alabama Power (the state's largest electric supplier) engages in integrated resource planning. The Public Service Commission (PSC) has not formally adopted an integrated resource planning standard, but notes that it has "ongoing knowledge of and involvement in Alabama Power's IRP process" (Alabama PSC 2007).
b As a response to a directive from the Alaska Legislature, the Alaska Energy Authority produced a regional IRP in 2010, but there is no formal process or IRP rule.
c Ten-year site plans (generation expansion and site planning) are presented to the PSC on an annual basis.
d There is no statute or rule relating to integrated resource planning; however, the Iowa Utilities Board may request a resource plan on an as-needed basis, and utilities do file them as part of docketed proceedings.
e Utilities may voluntarily file with the PSC for preapproval to construct new resources or modify existing resources.
f Utilities may voluntarily file with the PSC for preapproval to construct new resources or modify existing resources.
g While there is no IRP rule, the Tennessee Valley Authority (TVA) has voluntarily participated in integrated resource planning. TVA's most recent resource plan was released in March 2011; the plan prior to that one was released in 1995. TVA plans to start the process again in 2015.
h Utilities may voluntarily file with the PSC for preapproval to construct new resources or modify existing resources.
i Vermont's Sustainable Priced Energy Enterprise Development Program establishes a mechanism for the rapid procurement of renewable power by state utilities.

Source: Research conducted for EPA's Energy and Environment Guide to Action by Synapse Energy Economics

Integrated Resource Planning

IRPs are utility plans for meeting forecasted annual peak and energy demand, along with some established reserve margin, through a portfolio of supply-side and demand-side resources over a specified future period. As of early 2015, integrated resource planning is required or present in more than 30 states, including most vertically integrated states. See Figure 7.1.1 for a map of states with integrated resource planning, and see the introduction to Chapter 7 for an indication of which states have vertically integrated utilities. IRP processes vary in their degree of rigor, stakeholder feedback process, and degree to which they are subject to regulatory scrutiny. In states that conduct integrated resource planning, the process provides an opportunity to examine how energy efficiency, renewable energy, and CHP affect utility operations, customer costs, system reliability, and risk. State PUCs generally do not require or enforce specific findings or outcomes as part of the IRP development or vetting process. Thus, IRPs are generally not legally binding. Instead, regulatory commissions have formal proceedings to approve the content of the IRP, acknowledge that IRP processes were followed, or both. These proceedings differ by state. State PUCs may expect or require that significant deviations from IRPs be justified in rate cases or preapproval processes. IRPs do not negate the need for discrete resource approvals and should form the framework for other resource processes and decisions. Table 7.1.2 shows that many states have provisions for both integrated resource planning and discrete resource approvals, such as CPCNs.

Figure 7.1.1: States That Require IRPs



Source: Research conducted for EPA's Energy and Environment Guide to Action by Synapse Energy Economics, updated from Synapse 2013.

Discrete Resource Approvals

Discrete resource approval refers to a proceeding before a state utility commission in which a utility provides justification for a large capital investment in generation or transmission infrastructure. If the utility succeeds in justifying their investment, they are granted a CPCN. Some regulatory commissions or state statutes require that significant power plant additions, new plants, or large capital investments above a certain threshold go through this process. At least one state (Vermont) also requires large and lengthy power purchase contracts to get such an approval because of the potential financial risk and impact on customers. As of early 2015, at least 19 states have some form of CPCN (see Table 7.1.2), although not all states regularly exercise these statutes. Some states (such as Louisiana and Utah) without these statutes offer a parallel voluntary process. These processes maintain many of the same analytical and planning elements of integrated resource planning, but they include regulatory review by intervenors[60] rather than an interactive and potentially contested stakeholder process. Unlike integrated resource planning, CPCN processes are not a utility forum for gathering and disseminating information. Rather, they are a mechanism for utilities to justify discrete actions prior to regulatory approval. CPCNs are litigated processes argued before a state's public utility commissioner or

[60] Intervenors might include attorneys general, industrial groups, generation owners, transmission owners, land owners, consumer advocates, environmental groups, and other citizen action groups.

hearing official. CPCNs are legally binding and enforceable: a utility that obtains a CPCN from a PUC has generally proven, to the satisfaction of that PUC, that a plan is prudent.

The definition of when a CPCN is required differs from state to state. States that require CPCN or a similar proceeding for the acquisition of large new capital investments include Georgia, Indiana, Kentucky, Minnesota, West Virginia, and Wisconsin, among others. A CPCN provides the opportunity for state entities to ensure that energy efficiency, renewable energy, and CHP are considered on par with other capital investments. For example, the Vermont PUC requires this comparison as part of its discrete resource approval process, called a Certificate of Public Good.

A CPCN does not necessarily guarantee that a utility will recover the costs of a capital investment in rates; instead, it establishes that the choice to move forward with a capital investment is prudent at the cost, or cost range, established in the plan. To mitigate the risk of not recovering capital investments in rates after a project is in service, some states allow for preapproval or cost riders, through which utilities can begin recovering costs prior to the project being constructed. Even in this situation, the utility's project management is subject to review to ensure that any money wasted through poor project oversight is not charged to customers. Preapproval dockets are often coupled with CPCNs in a litigated process. By ensuring recovery, preapproval processes shift the risks inherent in planning to ratepayers; preapprovals generally release the utility from further regulatory review of discrete projects, unless costs are above utility expectations. States that have exercised preapproval or cost riders for generation additions include Indiana, Georgia, Kentucky, Kansas, Wisconsin, and West Virginia; other states may have unexercised provisions.

State Energy Planning Processes

States also maintain a regular or occasional executive or legislative-driven statewide energy planning process, wherein the state reviews policies and practices targeted towards specific outcomes such as resource utilization, economic development, or climate or other environmental goals. These plans may be completely independent of utilities—examining long-term and general policy measures with a particular end-goal—or may explicitly engage utilities and require companies to meet specific performance requirements (NASEO 2013a). By early 2013, at least 20 states were updating existing state energy plans or developing new plans, and at least 45 states will have operational state energy plans (NASEO 2013b). In addition, states may also conduct a form of planning to inform the development of specific state policies, such as renewable portfolio standards; energy efficiency resource standards; and funding levels for energy efficiency, renewable energy, and CHP programs.

Default Service

In restructured states, customers still have their electricity *delivered* by a regulated utility that operates the distribution network (i.e., a load-serving utility), but they may be able to choose the *source* of their electricity by comparing products and rates from a variety of companies. This process is known as retail choice, and the suppliers are called competitive retail suppliers (or something similar). Default service provisions ensure that load-serving utilities procure electricity for those customers who have not elected to choose a competitive retail supplier. In many of these states, default service is the primary supply option for residential and small commercial and industrial customers. As of April 2015, 15 states and Washington, D.C., offered whole or partial retail choice (EIA 2015) (see Figure 7.2 in the introduction to Chapter 7). Virginia and Oregon offer limited retail choice to large customers (Oregon 2001; Virginia 2007). Though retail choice has been an option for customers in these states for many years, the majority of residential load in these jurisdictions is served through procurement by a regulated utility (Aspen 2008).[61]

[61] Texas is one exception, as retail choice is required in this state. Eligible residential customers must choose a competitive supplier or they will be assigned one; however, customers in utility service areas outside of the Electric Reliability Council of Texas are not eligible, and municipally and cooperatively owned utilities may opt out of the program.

Default service requirements vary among jurisdictions. However, one common theme across requirements is the use of laddered contracts to minimize exposure of the default service load to price volatility. Under the ladder structure, only a fraction of the default service load is exposed to current market prices. Default service procurement typically reviews supply for periods as short as 6 months, or as long as 5 years. Therefore, default service planning requirements typically do not require long-term assessments of supply options outside the procurement period.

In some states such as Illinois and Maine, default service requirements specifically require that default service products meet state renewable portfolio standard (RPS) requirements. Because regulatory commissions approve default service rates, additional policies may be recommended in regulatory proceedings that could provide further price and stability benefits to customers. These could include cost-effective energy efficiency, renewable energy, and CHP carve-outs for a portion of the load dedicated to long-term contracts.

Long-Term Procurement Planning

LTPP requires that utilities prepare plans soliciting market-based electricity supply offers over a shorter time period than traditional integrated resource planning (typically 10 years or fewer). State policies that promote renewable energy resources have led to a return to these long-term resource planning practices, even in some restructured states with default service. When retail competition was introduced, utilities halted long-term planning efforts and relied on market competition to keep electricity prices low. However, when RPS policies began to be introduced, renewable resources often had higher capital costs and costs of delivered energy than conventional generation, and investors were hesitant to support these projects without guaranteed cost recovery well beyond the default service procurement window. As a result, regulators in many states began to require that utilities engage in LTPP. Unlike IRPs, procurement plans must often be updated every year. While some states like California allow load-serving utilities to own generation, LTPP processes usually evaluate purchases[62] for capacity and energy, as well as energy efficiency and other demand-side management programs. Default service states and states engaging in LTPP processes are shown in Table 7.1.2.

States with Existing Policies to Encourage Energy Efficiency, Renewable Energy, and CHP in Electricity Resource Planning

In addition to requiring resource planning, many states have enacted laws that require or encourage utilities to incorporate energy efficiency, renewable energy, and/or CHP into electricity resource planning. These policies range from requirements that all cost-effective energy efficiency be incorporated into planning to assessing the long-term risks and costs of new and existing fossil-generation stations. Electricity resource planning can be accomplished through a variety of modeling mechanisms, tuned to specific questions, as well as utility and regulatory requirements. The use and design of planning models are generally guided by best practices rather than explicit policies. With this in mind, the policies discussed in Table 7.1.3 also include those that states have taken to ensure that energy efficiency, renewable energy, and CHP are fairly considered in modeling. The last three policies are designed to ensure that planning processes are rigorous and lead to the actions for which they are intended.

[62] "Purchases" are distinguished from "acquisitions" with regard to the ultimate ownership of the resource. In an acquisition, the utility takes ownership of a resource and responsibility for that resource through its lifetime. A purchase agreement is a financial transaction for access to energy and/or capacity or other services through a specified time period.

Table 7.1.3: Policies States Use to Integrate Energy Efficiency, Renewable Energy, and CHP in Electricity Resource Planning and Procurement

Policy	Description	State Examples
Require third-party energy efficiency potential studies.[a]	Require, or have required, utilities to commission energy efficiency potential studies as part of planning process, or perform a statewide study for use in planning.	AR, CA, IA, IN, MA, OR, WI
Mandate all cost-effective energy efficiency in planning.	Require that utilities plan for all achievable cost-effective energy efficiency, or demonstrate that all supply-side and demand-side resources have been evaluated on a consistent and comparable basis.	CA, IN, MA, OR, Northwest[b]
Update assumptions for renewable energy capacity value, and supply and integration costs.	Require or explicitly note that renewable energy costs and attributes change over time, and should be kept up to date.	AZ
Quantify reasonably expected environmental regulations.	Have policies requiring cost consideration for future environmental regulations.	IN, OR, WY
Tie investment decisions to planning process and follow up on action plans.	Require that integrated resource planning result in an action plan with resource activities the utility intends to undertake over the next 2 to 4 years. Test investment decisions against integrated resource planning results.	IN, OR
Leverage existing knowledge from state utility and environmental regulators.	Have mechanisms for coordinating environmental permitting and utility electric planning.	CA, CT
Promote meaningful stakeholder involvement.	Provide funding opportunities for public interest stakeholders and intervenors in planning cases.	IN, ME, NY, OR, WI

States have also required one or more utilities to perform their own energy efficiency potential studies for use in planning processes. Example states include CA, CO, GA, IA, ID, IL, KS, KY, MA, MI, MN, MO, NM, NV, NY, OR, PA, TN, TX, UT, VT, WA, WI, and WY.

The Northwest Power and Conservation Council is mandated by the Northwest Power Act to incorporate all cost-effective energy efficiency into its regional electricity resource planning across Idaho, Montana, Oregon, and Washington.

Require Third-Party Energy Efficiency Potential Studies

Energy efficiency potential studies investigate new savings opportunities for specific measures and end-uses, customer segments, building types, and costs (see Chapter 2, "Developing a State Strategy," for details). While these studies are often used to develop short-term savings targets and budgets, they may also be used to inform utilities and policy-makers of long-term energy savings opportunities, which may then be used in utility integrated resource plans or long-term resource plans at the state or regional level. For example, the Northwest Power and Conservation Council (NWPCC) conducts energy efficiency potential studies for the entire region as part of its regional power plans, which seek "an electrical resource strategy that minimizes the expected cost of, and risks to, the regional power system over a long period of time" (NWPCC 2010b). Comprehensive energy efficiency potential studies provide the basis for setting near-term planning expectations and reasonable long-term trajectories in resource plans. For instance, Efficiency Maine Trust, the efficiency program administrator in Maine, commissioned energy efficiency potential studies to develop multi-year efficiency plans and goals (EMT 2012). Groups that specialize in the development of these studies are able to leverage experiences of multiple states, including those that have already evaluated achieved savings (PSC Wisconsin 2014; Vermont DPS 2011).

Mandate All Cost-Effective Energy Efficiency in Planning

Energy efficiency can provide a long-term, reliable, and low risk electricity resource. Efficiency avoids near-term energy and emissions, and it also avoids long-term capacity and transmission expansion requirements (see Chapter 1 for information on energy efficiency benefits). Some states have required utilities to develop long-term electricity resource plans that rigorously review opportunities to acquire and pursue all cost-effective energy efficiency. In some states, a comprehensive estimate of the avoided energy cost (as well as capacity and emissions) is used to characterize the amount of energy efficiency that is cost-effective (AESC 2013).[63] Other states, such as Oregon, require that "to the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets" (OPUC 2007). In 2003, California adopted a "loading order" for new resource requirements, which gives significant preferential treatment to energy efficiency as the primary mechanism for reducing and meeting new demand (California 2003).

Energy Efficiency Avoided Costs

To evaluate energy efficiency programs, states require the development of avoided costs to quantify energy efficiency benefits. Avoided costs are what would have been spent in the absence of the energy efficiency.

Avoided costs incorporated into planning processes include projected costs for electricity. Some states have expanded avoided costs to include emissions compliance, price effects, other resources (such as fuels and water), renewable energy certificates, transmission and distribution costs, and/or other non-energy benefits.

Update Assumptions for Renewable Energy Capacity Value and Supply and Integration Costs

As the market for renewable energy technologies expands, manufacturing and installation costs decline. Projecting a flat present-day cost and performance for renewable energy options may be an overly conservative estimate, undervaluing the likely contribution and benefit of these resources over the period of the electricity resource plan. In particular, if outdated costs and performance data are used, the plan may not even reflect contemporary costs—much less the expected declining costs in the future. In a recent review, the National Renewable Energy Laboratory (NREL) found that "most [interviewed] utilities had forecast a declining cost curve in their planning assumptions, only to see the actual costs decline much more steeply than anticipated" (NREL 2013). In a 2011 IRP, Portland General Electric found a significant decline in the cost of wind since its 2009 IRP (PGE 2011). In a 2011 IRP, Idaho Power asserted that declining solar photovoltaic (PV) costs would likely make this resource a more significant part of its portfolio in the future (Idaho Power 2011).

Quantify Effects of Reasonably Expected Environmental Regulations

Environmental regulations that are already promulgated and implemented may impose known costs or operating restrictions. Predicting the impact of regulations that are not yet finalized can be more difficult, but is still a critical element of prudent planning.[64] Oregon rules require utilities to account for regulatory compliance costs for carbon dioxide (CO_2) and criteria pollutants (OPUC 2007). Arizona requires that utilities

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[63] For this reason, avoided costs are extremely important to an IRP, as they help determine the amount of customer demand that can be met by energy efficiency and the amount that must be met by supply-side resources. Assumptions about costs for energy efficiency and demand response should be updated frequently to ensure that the amount of cost-effective energy is accurately represented as costs for these measures decline over time.

[64] For example, PacifiCorp states that with regard to integrated resource planning, "in parallel to administration of the Regional Haze rules, state agencies and EPA must also ensure compliance with other environmental regulations including the recently enacted Mercury and Air Toxics Standards (MATS), and emerging regulations for coal combustion residuals (CCR) handling and storage, Clean Water Act §316(b) cooling water intake rules, and effluent limitation guidelines (ELG). The Company must therefore assess not only currently known obligations, but must also assess reasonably foreseeable compliance obligations in its analyses" (PacifiCorp 2013).

"analyze and address in their plans environmental impacts related to air emissions, solid waste, and other environmental factors and reduction of water consumption and to address the costs for compliance with current and projected environmental regulations" (AZCC 2010). Similarly, draft integrated resource planning rules in Indiana require an analysis of how the plan conforms to the "utility-wide plan to comply with existing and reasonably expected future state and federal environmental regulations" (IURC 2012). Planning processes give utilities the opportunity to work with both the state and the stakeholder community as they address future environmental regulations.

Tie Investment Decisions to Planning Processes and Follow Up on Action Plans

Resource planning processes should be tied to anticipated real actions and activities performed by electric service providers. In many IRPs, the resulting near-term plan is termed the action plan, an explicit list of activities and procurements that the utility intends on completing based on the IRP. In some states, the approval of an IRP implies approval of near-term utility actions; in other states, approval of an IRP signals that the IRP's intent is reasonable, but the actual decisions may be contested at a later date, such as through a CPCN process. Regardless of the intent, states have found that utilities file action plans to make explicit their intent following planning proceedings, and states follow up on action plans to assess if the planning process has resulted in expected outcomes. State requirements for action plans vary. Georgia requires that utilities provide "a description of the major research projects and programs the utility will continue or commence during the ensuing three-year period, and the reasons for their selection" (Georgia 1997). At a more detailed level, Arizona requires that "with its resource plan, a load-serving entity shall include an action plan, based on the results of the resource planning process, that: (1) includes a summary of actions to be taken on future resource acquisitions, (2) includes details on resource types, resource capacity, and resource timing, and (3) covers the three-year period following the Commission's acknowledgement of the resource plan" (AZCC 2010).

Leverage Existing Knowledge from State Utility and Environmental Regulators

Some states leverage existing knowledge and expertise between utility regulators and environmental regulators to help inform utility plans. Permits issued by environmental regulators may explicitly shape utility actions and planning outcomes. Therefore, states have found significant benefits from enhanced dialogue between utility and environmental regulators (RAP 2013). In particular, this communication can help inform coherent, multi-pollutant-aware permitting processes, help PUCs respond and prepare for existing and emerging environmental regulations, and ensure that decisions from agencies do not work toward cross-purposes.

States that explicitly coordinate utility and environmental regulators do so using a wide variety of mechanisms. In 2011, the Oklahoma Corporation Commission opened an inquiry to examine current and pending federal environmental regulations, drawing on expertise from state environmental regulators and stakeholders (OCC 2011). Similarly, Oregon has opened a planning process with public input for the Clean Power Plan; comments by Oregon Department of Environmental Quality were submitted in cooperation with the Department of Energy and PUC (ODEQ 2014). In a more formal move, the Colorado Clean Air Clean Jobs Act explicitly requires the approval of the state Department of Public Health and Environment, and requires that "the Commission shall not approve a plan except after an evidentiary hearing and unless the Department has determined that the plan is consistent with the current and anticipated requirements of the federal [Clean Air] Act" (Colorado 2010). Recognizing the value of collaboration, the Connecticut Department of Energy and Environmental Protection (CT DEEP) was created in 2011, merging the Department of Environmental Protection, the Department of Public Utility Control, and energy policy staff from other areas of state government. The new DEEP oversees the roles of utility and environmental regulators to "integrate energy and environmental policies and programs in a more systematic, proactive and coherent manner" (CT DEEP 2014). CT DEEP and the

Connecticut Energy Advisory Board are required to prepare a statewide Comprehensive Energy Strategy every 3 years (CT DEEP 2013).

Promote Meaningful Stakeholder Involvement

States have found it useful to consider mechanisms of funding or supporting public interest and environmental interest intervenors in utility planning procedures. Stakeholder processes can help ensure that the concerns of ratepayers and environmental advocates are taken into consideration, and often represent some of the strongest, continually engaged parties advocating energy efficiency, renewable energy, and CHP options. Some states offer intervenor funding through application, where funding is drawn from regulated utilities. In Oregon, the PUC establishes an agreement wherein energy utilities provide "financial assistance to organizations representing broad customer interests" (OPUC 2012a). Wisconsin provides for intervenor funding for individuals or organizations that are affected by the proceeding, have a material interest, and are unable to participate if not otherwise funded (WI PSC 1995). In Indiana, the Utility Rate Payer Trust was established through the settlement of litigation regarding a canceled project; the Trust is overseen by a five-member committee (IN OUCC 2013). Typically, intervenor funds are allocated to public interest groups who advocate for views not adequately represented by utility or large industrial consumers.

Designing Effective Electricity Planning Policies

In many states, specified planning and procurement processes help to level the playing field for energy efficiency and clean energy supply. This section describes key components of an effective planning and procurement process, including participants, timing and duration, and consideration of key factors that can affect the results of utility planning analyses.

Participants

Planning is not typically conducted in a vacuum: utilities engage with stakeholders, intervenors, regulators, and the public through either collaborative or litigated processes. Various electric system planning and procurement processes engage a range of participants, including those who conduct, review, and ultimately approve the process.

- *Utilities.* Load distribution companies (LDCs) and utilities can either be investor-owned utilities (IOUs), municipal government entities, cooperatively owned utilities run by industrial and residential consumers, or even federal entities (as in the case of the Tennessee Valley Authority [TVA] and Bonneville Power Association). Generally, rates and costs at IOUs are regulated by state PUCs, while a municipal government operates and oversees municipally owned utilities; member-owners oversee cooperatives. Under most circumstances, IOUs have the greatest degree of state oversight through integrated resource planning, CPCNs and preapproval dockets, and ultimately rate cases. In some states, municipally and cooperatively owned utilities may not be required to submit plans for state review (except environmental permitting).
- *Regional transmission organizations (RTOs)*. RTOs are responsible for the reliability and adequacy of the transmission system, which directly affects the planning process. Adequacy needs focus on load forecasting and studies to address retirements and new resources. Reliability needs focus on regional and specific planning studies commissioned by the RTO. State agencies often engage and participate at the committee and sub-committee levels within the RTO.
- *State PUCs*. State PUCs and their technical staff oversee, engage in, and/or monitor most state planning processes, including integrated resource planning, CPCN, and—in retail-choice states—default service or similar procurement proceedings. PUCs are concerned with costs, risks, rate impacts, reliability, and

continuity of service. Many PUCs do not have direct knowledge of environmental regulatory matters or permitting processes, and may rely on utilities and other regulated entities to present that information. The PUCs' primary enforcement mechanism is the regulation of rates and financial incentives or penalties to utilities. PUCs generally have a wide range of latitude in these matters.

- *State environmental regulators.* State environmental managers and air offices have extensive expertise in the regulation of effluents and emissions. Their responsibilities, which include permitting and setting emissions standards for electricity generators, influence utility electricity resource decisions. Environmental regulators may also be able to provide information about proposed or pending environmental regulations. Thus, some states have found benefits in strengthening relationships and communication between environmental regulators and PUCs.
- *State legislatures, governors, and energy offices.* Elected state representatives may create state policies that either incentivize or require particular actions from LDCs (such as an energy efficiency resource standard [EERS] or RPS) or generators (such as carbon regulation in the Regional Greenhouse Gas Initiative and California), or provide guidance or requirements to PUCs (such as the guaranteed recovery of rates for environmental expenditures). State representatives and governors may not directly engage in specific utility plans. In some states, the governor is indirectly represented through the Attorney General's office or a state ratepayer advocate, and/or through the participation of state energy offices, which are charged with implementation of state policies and aligning those policies with those enacted at PUCs.
- *Stakeholders and intervenors.* Where planning and procurement processes occur, they are reviewed, commented upon, and/or audited by a variety of stakeholders and intervenors. In most states, a consumer advocate office represents the interests of residential (and sometimes commercial) ratepayers; these advocates may or may not have an interest or opinion regarding the procurement of energy efficiency, renewable energy, and CHP. Industrial consumers are actively engaged in state planning processes, usually to minimize impacts on large consumers. Finally, environmental advocacy groups are increasingly engaged in both statewide planning processes and specific utility planning proceedings, including integrated resource planning, CPCN, preapproval, and default service dockets.

Timing and Duration

Both integrated resource planning and portfolio management for default services occur on a regular planning and/or solicitation cycle, which can range from 1 to 5 years depending on the state. CPCN and preapproval dockets are triggered by specific utility actions, changes in commodity or market prices, or regulatory compliance obligations, and do not necessarily adhere to a regular or predictable schedule. IRPs typically take anywhere from a half year to a full year to complete, depending on the stakeholder engagement processes, and in certain instances can extend into the next IRP cycle. In contrast, docketed processes—such as CPCN, preapprovals, and default service proceedings—may pass through a regulatory proceeding in as few as 3 months to as long as 6 months or more.

Planning and portfolio management typically requires reviewing decisions and investments with long lives or extended spending; portfolio costs and risks are thus reviewed over a long term, from 10 to 30 years. In IRPs, short-term "action plans" usually include specific near-term actions or investments that are likely to result from the IRP. These action plans range from 1 to 5 years forward from the IRP.

Some states provide or require intracycle IRP updates or reviews, in which prices, regulatory conditions, and model results are updated and checked.[65]

Interaction with State, Regional, and Federal Policies

Utility and electricity generator operations, planning, and financial decisions are governed by state and federal rules and regulations. In addition, RTOs and independent system operators (ISOs) engage in regional transmission planning that may affect utility decisions. States have found it useful to consider these state, regional, and federal policies in electricity resource planning. In turn, findings from electricity resource planning are also considered in the design and implementation of related policies. Standard planning practice requires that utilities and generators follow legal requirements for emissions, system reliability, renewable procurement, and efficiency investments, among other considerations.

Energy Efficiency Resource Standards and Renewable Portfolio Standards

Some states maintain EERSs and/or RPSs, or minimum requirements for utilities (see Section 4.1, "Energy Efficiency Resource Standards," and Chapter 5, "Renewable Portfolio Standards"). Because these standards generally represent a rule of law governing utility operators, states require their inclusion in electricity resource planning. States have also found it useful to consider and model pending portfolio or efficiency standards or goals, although pending or voluntary measures may be modeled as a sensitivity or uncertainty instead of as the reference case. Some states require that EERSs and/or RPSs be treated as a floor, rather than as a default procurement level that utilities should meet but not exceed. For example, Oregon requires that utilities seek all cost-effective energy efficiency regardless of whether the utility or a third party administers efficiency programs.[66] Utility planning processes can also consider other state policies that may be in place, such as interconnection and net metering standards that govern the integration of onsite generation resources (see Section 7.3, "Interconnection and Net Metering Standards"), as well as other policy types discussed elsewhere in this chapter.

Environmental Regulations

States typically require that utility resource planning include existing state and federal environmental regulations governing utility or generator operations. Including proposed, pending, and emerging regulations in utility planning ensures that social and environmental costs are reasonably anticipated and their effects quantified. In return, electricity resource planning can sometimes help to inform environmental planning, as some environmental compliance plans leverage electricity resource planning to find a reasonable least cost mechanism for meeting environmental requirements. For example, recent experience in regional haze planning in some western states has sought alternative compliance measures requiring tradeoffs between generators. EPA recently approved a Regional Haze State Implementation Plan (SIP) revision in New Mexico that calls for unit shutdowns at San Juan Generating Station and lower cost compliance at remaining units rather than more stringent controls across all units (EPA 2014b). This plan resulted from utility planning that indicated a lower cost for an equally rigorous alternative SIP than the original promulgated Federal Implementation Plan.

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[65] For example, utilities in South Carolina must submit IRPs to the PSC every 3 years and update them annually (South Carolina 2011).

[66] The Oregon PUC's "Investigation into Integrated Resource Planning" mandates that utilities "Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs" (OPUC 2007).

Regional Transmission Planning

RTOs and ISOs engage in long-term transmission planning. Decisions regarding the maintenance or enhancement of transmission facilities have important consequences for the development of generation and energy efficiency resources. Electricity resource planning may consider not only the generation resources that are available with the existing transmission system, but also those that could be accessible via new or upgraded transmission lines. Planning processes can also consider whether costly transmission upgrades and enhancements can be deferred or avoided due to increased energy efficiency, distributed renewable energy, and CHP. The transmission planning process requires that the RTOs/ISOs understand which resources are likely to be available in future years, including energy efficiency, renewable energy, and CHP. In some regions, such as ISO New England (ISO-NE), energy efficiency programs are explicitly considered in transmission planning. States engage in RTO/ISO planning via representatives on market rules committees and by providing feedback in regional transmission plans.

Consideration of Key Factors in Analysis

States have found that the most effective planning processes require appropriate treatment and documentation of key assumptions used in utility analyses. Key assumption categories that may significantly alter planning analysis results are discussed below. Many assumptions used in planning are considered proprietary by utilities, potentially including load forecasts, fuel price forecasts, costs of demand- or supply-side resource options, transmission costs, emissions costs, models, and more. States differ as to what information they require to be made public. In the case of proprietary data, only those intervenors signing protective agreements are granted access to these data.

Load Forecast

A load forecast (annual peak and energy) plays a key role in determining the need for new and existing resources, as well as the type of those resources; it provides the fundamental basis for any energy planning process. For example, a utility that expects to retire a power plant can forecast customer demand first and then assess electricity supply options to determine whether all retirements must be replaced with new, similarly sized generators in order to meet demand.

In vertically integrated states, the utility often develops its own demand projection. Because a utility's demand forecast is so important to the resulting resource plan, states may require utilities to base forecasts of future load on realistic assumptions about local demographic changes and local economic factors (i.e., the movement of industry and housing), and to fully document these assumptions. Forward-looking resource requirements can change quickly, based on changing economic realities, energy prices, and projection methods. Frequent updates to load forecasts allow for reasonable planning.[67]

In states with restructured electricity markets, demand projections are developed jointly between utilities and RTOs. This regional long-term load forecast is one foundation to help ISOs/RTOs determine the need for future transmission projects. Some regions, like New England, develop load forecasts of peak demand and energy requirements based upon econometric models. ISO-NE's forecasts of annual energy for New England as a whole and for each individual state and load zone is based on previous usage along with real electricity price,

[67] In 2009, the Michigan Planning Consortium conducted a load forecasting survey for the Michigan Public Service Commission designed to help improve the planning process for electricity infrastructure projects. Survey responses were received from ITC, Wolverine, Detroit Edison, Consumers Energy, Indiana Michigan, Michigan South Central Power Agency, Alepna Power, ATAC, PJM, and MPPA. When asked about load forecast frequency, the majority of respondents said that load forecasts are updated at least annually and some more frequently (MPC 2009).

real personal income, gross state product, and heating and cooling degree days. ISO-NE adjusts its forecast based on its expectations of energy efficiency program effects (ISO-NE 2014a).

Regulatory Environment

Numerous policies and regulations that affect electric utilities have been promulgated at the federal, regional, and state levels, with several others either proposed or under consideration. As previously discussed in this section, key policies interacting with electricity resource planning include EERSs, RPSs, environmental regulations, and regional transmission planning. These policies and regulations, both individually and in combination, have the potential to dramatically change the electric power industry. Existing rules may affect utility operations in the present, and rules that have been proposed or that are under consideration will likely affect utilities at some future date.

Because electricity resource planning examines and evaluates scenarios over the long-term—inclusive of any rules or regulations that will affect a utility over the planning period—several states effectively require utilities to analyze the impact of promulgated, proposed, planned, and emerging environmental regulations on the costs, benefits, and risks of proposed resource portfolios.[68] In 2013, Georgia Power Company submitted an IRP evaluating plant decommissioning and new plant additions; the utility's analyses detailed how future regulatory considerations could affect financial decisions made in 2013 (Georgia Power 2013).

States have found that consideration of these rules may result in a utility including an emissions allowance price in its analysis, planning for the installation of one or more pollution control technologies, changing the operations of one or more generating units, or procuring alternative types of supply- and demand-side resources needed to meet demand.

Supply Options

Across resource types, capital costs, operation and maintenance expenses, and variable fuel costs, if any, will vary. How often the resource will generate electricity, as well as how new or modified generation assets are financed, can also affect supply option inputs. States have found that electricity resource planning provides an opportunity to examine a wide range of options for meeting consumer requirements, including traditional generating resources, energy efficiency, renewable energy, CHP, and storage options. Resource planning may, by default, review only traditional resources and either exclude or make *a priori* assumptions for renewable energy supply options based on either regulatory requirements or a premise of achievable outcomes.

Improvements in renewable energy technologies have driven capital costs down while increasing the capacity factors of these intermittent resources (ACEEE 2014). The installed costs of solar PV modules continued their precipitous decline through 2013: the cost of residential and commercial modules dropped another 12 to 15 percent from 2012 costs, while achieving efficiencies of 14 to 16 percent; meanwhile, installed prices dropped by more than a third from 2009 to 2013 for utility-scale PV projects, while the capacity factor across all utility-scale projects has grown to 27.5 percent (LBNL 2014c).[69] The evolution of wind projects has been no different: nationwide, wind projects averaged a capacity factor of 32.1 percent from 2006 to 2013, even reaching 38 percent in the Interior in 2013. Meanwhile, costs have continued to fall, both for project developers—the capacity-weighted average installed cost of projects in 2013 dropped to $1,750/kilowatt—and for power purchasers. According to the U.S. Department of Energy (DOE), "wind PPA [power purchase agreement] prices

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[68] This rule may not be reflected in written regulation, but experienced state regulators have recognized that a failure to account for impending regulations puts ratepayers and utility decisions at risk.

[69] The project-level range of capacity factors is 16.6 to 32.8 percent (LBNL 2014d).

have reached all-time lows," falling to an average of $25/megawatt-hour (MWh) nationwide (LBNL 2014a). Nevertheless, many of these resources may still be overlooked in utility resource planning.

To ensure reasonable planning, many states require that utilities: 1) not place limits on renewable energy options without rigorous justification, and 2) examine non-traditional resources such as CHP, onsite generation, and demand-side management with the same rigor as traditional resources. For example, Oregon requires that utility IRPs consider a full range of resource options, typically including renewable energy, storage, and traditional fossil generation.[70]

The availability and costs of raw materials and skilled labor, construction schedules, and future regulations can all present uncertainties. Because these cost uncertainties can affect technologies in different ways, states have found it useful to require utilities to model a range of possible costs and construction lead times for supply alternatives. In addition, some states require utilities to evaluate supply technologies that are not currently feasible from a cost perspective, but may become so later during planning periods, which typically last a decade or more. Hawaii, for example, requires that utilities consider all feasible supply- and demand-side resource options available within the years encompassed by the IRP horizon (Hawaii PUC 2011).

Some states have found that when significant renewable energy procurement is planned, utilities might have concerns about the integration of variable resources. In these cases, planning for renewable integration may be a critical component of achieving more substantial renewable energy. Renewable energy integration studies are engineering documents that help specify what types of other system resources are required to stabilize energy delivery and transmission. The results of these studies may partially guide supply choices and/or the costs of incremental renewable energy. Arizona Public Service, for example, analyzed and presented integration costs for renewable resources in the portfolios it evaluated in its 2012 IRP (APS 2012).

Finally, economic retirements of existing resources are part of electricity system planning. Some states have found it useful to require utilities to consider retiring and replacing existing resources with a single resource or a portfolio of resources. In a 2013 IRP, Georgia Power Company evaluated the economic benefit of maintaining and retrofitting each of its existing coal-fired generators against a replacement option. Since 2011, PacifiCorp (a northwestern utility) has evaluated the economics of select coal units in addenda to IRPs.[71]

Demand-Side Resources

Some states require electricity resource planning to include an evaluation of energy conservation and/or efficiency. However, the extent to which demand-side resources are actually considered varies from state to state. A number of utilities consider energy efficiency as a competitive resource relative to supply-side options in their long-term planning, but others assume either a regulatory minimum or a series of modest efficiency goals. States with rigorous energy efficiency planning—such as Massachusetts,[72] Minnesota,[73] and

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[70] Oregon PUC Order 07-002 on IRP Guidelines requires "identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology" (OPUC 2007).

[71] For example, see PacifiCorp's 2013 IRP Update regarding Cholla Unit 4 (PacifiCorp 2014).

[72] Massachusetts requires that electric and gas distribution utilities acquire all available cost-effective energy efficiency resources under An Act Relative to Green Communities (Massachusetts 2008). These utilities are also required to file 3-year energy efficiency plans with the Department of Public Utilities on a triennial basis beginning in 2012.

[73] Minnesota's Next Generation Energy Act of 2007 (Minnesota Statutes 216B.241) established an energy savings goal of 1.5 percent of average retail sales for each electric and gas utility beginning in 2010. Utilities must file Conservation Improvement Program (CIP) plans every 3 years, detailing programs offered to assist residential and business customers to become more energy-efficient. Utilities report their actual CIP spending and savings on an annual basis.

Washington[74]—require utilities to submit efficiency potential studies, budgets, savings targets, and evaluations for approval by regulatory commissions.

States have found that credible and independent energy efficiency potential studies of demand-side resources can be critical to state and utility plans and acceptance. These studies identify and examine the technical, economic, and achievable potential of new energy efficiency within a market. These data inform decision–makers, and the outcome of an energy efficiency potential study may be incorporated directly into electricity resource planning and state energy planning processes.

Some states require all cost-effective energy efficiency to be included in electricity resource planning. The mechanism by which energy efficiency is valued is highly relevant to its incorporation in planning. If only utility costs are assessed, some states have found it reasonable to review only utility benefits (i.e., the ability of energy efficiency to avoid higher cost supply options), but if both utility and participant costs are assessed, planning processes may also review participant and societal benefits. Massachusetts, a leading state for implementing energy efficiency, requires the Total Resource Cost test as part of its 3-year planning process (MA DPU 2009). For more information on cost-effectiveness tests, see Section 4.2, "Energy Efficiency Programs."

Transmission and Distribution

As discussed in the electricity grid overview in the introduction to Chapter 7, utilities rely on an extensive network of transmission and distribution lines in order to deliver electricity to customers. States generally require utility electricity resource planning to reflect constraints in existing transmission (and sometimes distribution) systems; these constraints may limit the location or types of supply resources that can be added to (or removed from) the system. In highly constrained systems (i.e., where transmission is binding through multiple hours of the year), resource planning may be oriented around overcoming such constraints through transmission improvements, demand-side management, and strategically placed generators. For example, Indianapolis Power and Light used the PROMOD IV model to analyze five possible locations for a new gas-fired combined cycle generating unit. The model examined the potential transmission congestion costs associated with each location to help determine the optimal location for siting the new generating unit (IPL 2013). Models will vary in the extent to which they represent specific localized transmission constraints. Modeling also typically assumes additional cost and construction timing if new interconnection infrastructure is required, such as new transmission lines to reach new wind farms.

Transmission constraints may play a role in procuring renewable energy, particularly when utilities consider how to integrate more significant blocks of variable renewable energy (such as wind and solar). Such questions are generally addressed through technical integration studies. Because demand-side management programs generally do not require transmission (as they are implemented at load, rather than across wires), states have found that these programs can pose a significant quantifiable benefit for transmission constraints—a benefit that can be considered in resource procurement and planning.

[74] Washington voters passed Initiative 937 in 2006, which calls for electric utilities serving more than 25,000 customers to undertake all cost-effective energy conservation. This Initiative was enacted into law as the Energy Independence Act. Qualifying utilities must pursue all available energy efficiency that is cost-effective, reliable, and feasible. Utilities are required to identify efficiency potential through 2019, submit reviews and updates every 2 years for the subsequent 10 years, and establish and meet biennial conservation targets (WA Initiative 2006).

Planning can also account for, and accommodate, inevitable generator outages and transmission failures. RTOs typically review supply, demand, and transmission infrastructure to estimate a "planning reserve margin," a measure of how much the system must be overbuilt to maintain reliability under adverse conditions.

Commodity Prices

The expected future prices of fuel, electricity purchased from regional markets, and emissions can influence the economic consideration of existing and new resources, and thus the relative economics of avoiding those resources through the use of energy efficiency, renewable energy, and/or CHP (see text box on p. 7-7-16 for further discussion of avoided costs). In some regions, energy efficiency, renewable energy, and CHP must compete in an open market; the degree to which these resources are considered competitive depends on commodity price assumptions.

- *Fuel prices*. The economic viability and hourly dispatch of power plants is highly sensitive to fuel price forecasts. Fuel prices represent an important, if not primary, component of the overall cost of generation for facilities using gas, coal, or biomass, as well as the relative competitive value of clean energy resources that do not consume fuel. Because prices change over time, sometimes dramatically, an up-to-date fuel price forecast is critical. In some states, utilities review multiple third-party fuel price projections and present a range of potential outcomes. For example, the Wisconsin Public Service Company incorporates regular updates to its fuel price forecasts; PacifiCorp updates its fuel price forecasts on a quarterly basis (PacifiCorp 2005; WI PSC 2011).
- *Electricity and capacity market prices.* Electricity market prices refer to the wholesale cost of energy (in $/MWh) available to resources that either sell on an open spot market or sell to other utilities. In organized markets (PJM, Midcontinent ISO [MISO], ISO-NE, Electric Reliability Council of Texas, California ISO, and Southwest Power Pool), past market prices are published (PJM 2015). In other regions, market prices are implied, but represent the price that a utility could command by selling its excess energy to a neighboring utility. Capacity prices refer to the wholesale cost of maintaining capacity (in $/megawatt [MW]) for the purposes of meeting peak load. In PJM, ISO-NE, and, to a lesser extent, MISO, capacity is sold on a wholesale market.[75] Energy prices are directly related to fuel prices, but an electricity system model is required to derive market prices. States have found value in updating energy price forecasts with fuel prices. Capacity market prices are established through different mechanisms, and are the subject of continued debate.[76]

Modeling Approach

All electricity system plans require some level of electricity system modeling. Electric system models are designed to answer different types of questions, from large-scale regional or national models, to highly detailed electricity generator-specific dispatch simulation models. In general, larger scale, long-term models[77] are designed to evaluate different federal or regional policies and forecast how these policies will affect multiple electricity generators. Simulation dispatch models (also commonly referred to as "production cost" models) are designed to determine how one or more individual generators will dispatch into the electricity grid on an hourly (or even 15 minute) basis over a period of months, and how specific generators compete against each other. Policy-scale models simplify dispatch and individual unit operations, and detailed models generally

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[75] See for example: PJM (2014), ISO-NE (2014b), and MISO (2012).

[76] Recent rule changes by the Federal Energy Regulatory Commission, for example, may significantly change the future of capacity prices in regions with an open capacity market.

[77] For example of larger scale, long-term models, see EPA (2014a) and EIA (2014).

look at shorter, well-defined timeframes and conditions. Between these two extremes are models designed to determine what types of generators a utility may want to invest in, called capacity expansion models, and models designed to review how uncertainty in forecast prices or conditions affects individual generators.

Integrated resource planning, CPCN, default service, and LTPP are not restricted to the use of one of these models, although capacity expansion models are commonly used to evaluate which resource choices best meet customer requirements for a utility. In some states, models are used in sequence to define regional outcomes, then electricity market prices, and then individual electric generating unit (EGU) behaviors. Each model will have its own strengths and weaknesses when it comes to answering a particular question or reflecting particular behaviors of the power system. It is important to note that almost all of the models used for these purposes are licensed by model vendors and require significant expertise to operate and vet. Input assumptions about individual generating units (such as ramping ability or maintenance outages) may be considered proprietary information. Thus, while models are the framework in which assumptions are used, they are often also the most complex and opaque components of utility planning. Model structures are discussed in more depth in EPA's Technical Support Document entitled "Projecting EGU CO_2 Emission Performance in State Plans" (EPA 2014c). For examples of how various states have applied models for integrated resource planning, see the Lawrence Berkeley National Laboratory's "Survey of Western U.S. Electric Utility Resource Plans" (LBNL 2014b).

IRP and CPCN Outcomes

IRPs are designed to produce a single "preferred" set of resources to serve customer requirements, including new resources, changes to existing resources, and demand-side resources expected to be required over the planning period. Capacity expansion modeling typically results in one or more sets of suitable resource mixes for a utility—i.e., resources that meet customer requirements and, under some set of circumstances, are least cost. Further analyses of these resource mixes, which examine total cost, risk and uncertainty, and (sometimes) rate impacts, produce a single preferred portfolio. Portfolios are evaluated under different scenarios, which represent distinct policy or risk outcomes, and different sensitivities, which represent uncertainty around specific input variables. In its 2011 IRP, for example, PacifiCorp defined input scenarios for portfolio development, examining alternative transmission configurations, types of CO_2 regulation, and renewable resource policies. Sensitivity cases that were analyzed included varying fuel costs, load forecasts, and demand-side management resource availability. PacifiCorp modeling resulted in 100 simulation runs, and top resource portfolios were determined after an examination of the resulting portfolio costs (PacifiCorp 2011). The short-term investments and utility changes either indicated or implied by this portfolio may be translated into an "action plan," which describes the next steps to be pursued by the utility and/or regulators.

CPCN evaluation structures are designed to review the costs, benefits, and risks of a discrete action or set of actions, such as the acquisition of a new resource or significant modification of an existing resource. The planning and analysis of CPCNs are very similar to IRPs, except that rather than resulting in one or more sets of suitable resource mixes, the purpose of the CPCN is to estimate the utility and/or customer cost with and without the acquisition of the resource under scrutiny. Instead of producing a set of resource mixes, the CPCN reviews a set of discrete resource options and again views them through the filter of total cost, risk and uncertainty, and (sometimes) rate impacts. In 2011, for example, Northern States Power in Wisconsin filed an application requesting a CPCN for a proposed upgrade to the existing transmission line system, adding a new 161 kV line to the existing 69 kV line between two of its substations (NSPW 2011). The company's application detailed the preferred route for the lines, two alternate routes, and the projected costs, impacts, and benefits of the project. The final outcome from a utility's CPCN application is the selection of the resource and recommendation for the CPCN.[78]

Implementation and Evaluation of Electricity Resource Planning

Much of electricity planning consists of ensuring that the right framework and assumptions are in place to develop a reasonable and cost-effective plan. Planning implementation is the development of these assumptions and the vetting of the framework—a process that is effective when utilities, regulators, and other stakeholders are involved in implementation.

Administering Body

In most states, the utility is generally responsible for implementing the planning or procurement policy. State PUCs oversee the utility planning processes in their states. Typically, the commissions solicit comments and input as they develop planning and procurement practices from a wide variety of stakeholders, including generation owners, default service providers, competitive suppliers, consumer advocates, renewable developers, environmental advocates, and energy efficiency advocates. The utility regulator may also play a role in reviewing and approving utilities' planning procedures, selection criteria, and competition solicitation processes. PUCs in different states take different roles in the IRP process. In some states, such as Oregon, California, Indiana, and Georgia, the review and evaluation of IRPs are conducted in a docketed forum, in which commission staff and stakeholders are able to both issue formal or informal discovery and comment on the IRP's assumptions and construction. Electricity procurement for default service customers and larger scale CPCN processes are almost always docketed, litigated proceedings, with supporting testimony and a multiple-month schedule of discovery and fact-finding, pre-filed testimony, and often oral argument. PUCs make the final determination of whether default service and/or CPCN are acceptable.

Cooperatively owned utilities and municipal electric boards may not be subject to formal state PUC oversight. In the case of cooperatively owned utilities, boards appointed by member-customers are charged with supervision; municipal governments that supply electric services regulate their own utilities. In rare cases, such as in Kentucky, the PUC reviews and regulates cooperatively owned utilities (KY PSC n.d.). The TVA has little or no state administration, although the utility delivers to 155 local distribution companies that are subject to state requirements.

Evaluation

State PUCs may review a variety of metrics in evaluating the outcome of a utility plan. "Least cost" is generally the dominant factor in consideration, although PUCs will consider reliability implications, short-term rate implications, and price stability. Least cost generally refers to the lowest long-term system cost discounted to present day dollars. As such, the definition requires the consideration of long-term costs, and may be highly dependent on forecasts for commodity prices and expected future regulations. Utilities seek to generally prepare plans that are consistent with PUC requirements and preferences.

States vary in the extent to which they review elements of the utility planning process. In some states, such as Oregon and Nevada, PUCs conduct a rigorous review of IRP assumptions and processes; in other states, such as Indiana and Kentucky, the state allows stakeholders to probe utility plans through formal or informal discovery

[78] CPCNs are typically applications put forth by utilities seeking approval of particular actions. As such, utilities have typically conducted a planning process they consider complete, opened to scrutiny under a litigated proceeding. Therefore, a utility only files an application that supports and recommends the CPCN.

and a comment process (Indiana 2014; Kentucky 1995). IRPs may be approved, approved with conditions, or sent back to utilities to revise their assumptions or processes. Some states do not require formal review of IRP processes or results.

PUCs rarely require a look-back period or post-hoc review of utility plans, recognizing that actions perceived to be least cost at one point in time may shift with changing circumstances. In rate cases (not planning dockets), utilities are required to show that investments and commitments were prudently incurred—i.e., the utility conducted reasonable planning at the time that the investment was made. To the extent that a utility action is found to be imprudent, PUCs may opt to penalize utilities for damages incurred (i.e., the cost difference between a reasonable course of action and the utility's decision) and/or issue a penalty for poor management. In 2012, the Oregon PUC found that a utility decision to install emissions controls was imprudent because reasonable utility planning should have otherwise found that the EGU was not economical to retrofit; the PUC imposed a $17 million penalty for poor management and an imprudent decision (OPUC 2012b). In an Indiana CPCN process, the PUC granted a utility permission to proceed with an emissions retrofit, but penalized the utility $10 million for having conducted a poorly executed planning process (IURC 2013).

Updates and Progress Reports

Regulators sometimes require utilities to submit electricity resource plans and progress reports at regular intervals. These plans and reports describe in detail the assumptions used, the opportunities assessed, and the decisions made when developing resource portfolios. Regulators carefully review these plans and either approve them or recommend changes needed for approval.

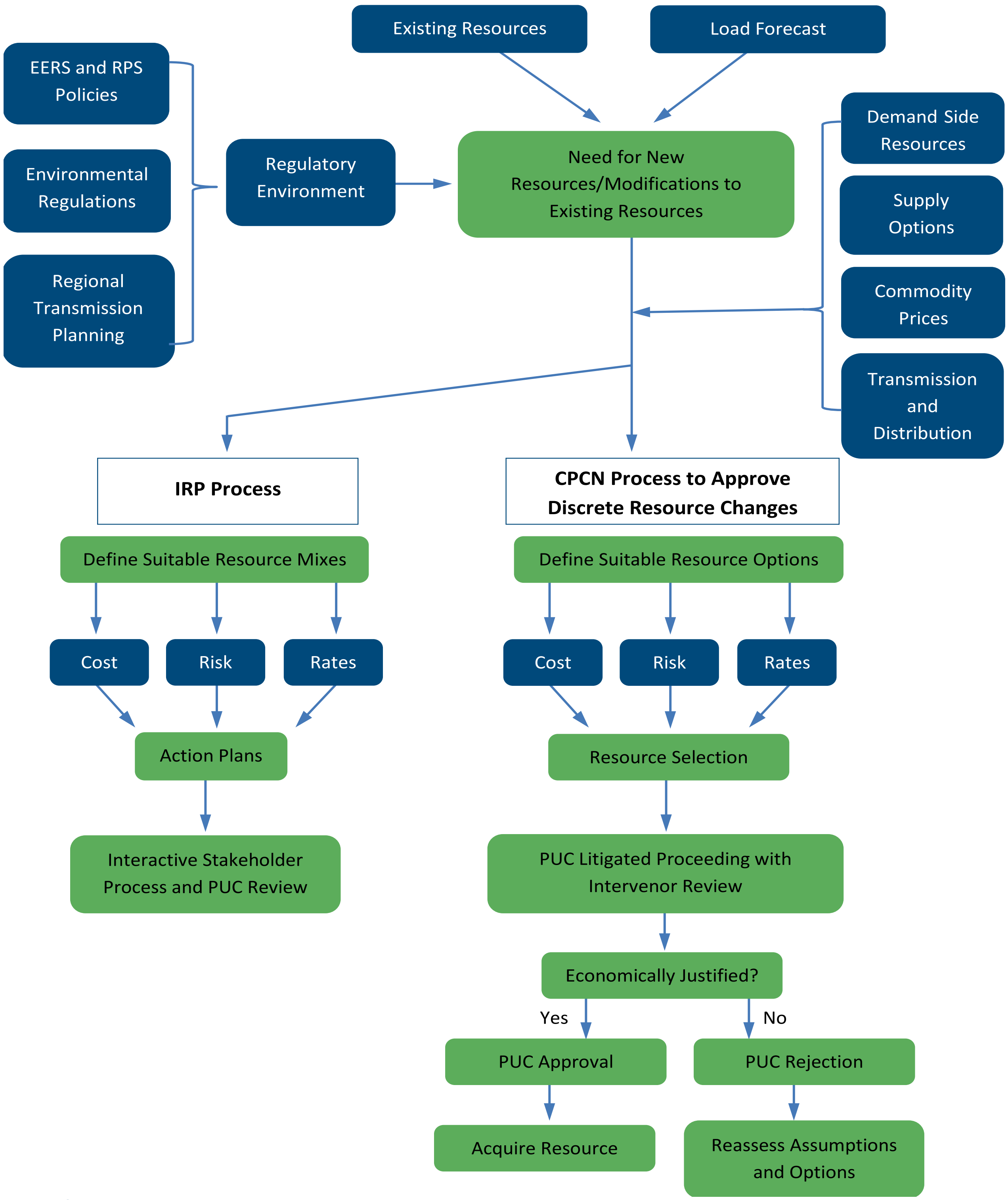
Oregon requires utilities to submit biennial IRPs and annual IRP updates (OPUC 2007). Similarly, the Iowa Utilities Board requires companies to submit annual reports on their energy efficiency and load management programs (Iowa 2014). The NWPCC's 2005 plan calls for monitoring key indicators that could affect the plan, such as loads and resources, conservation development, cost and availability of wind generation, and climate change science. This monitoring will inform IRPs developed by the utilities in the NWPCC region (NWPCC 2010b).

Applying Electricity Resource Planning Results

Integrated resource planning provides a mechanism for vetting and reviewing utility planning procedures, but it does not necessarily require specific utility actions. While some states require utility actions (such as resource acquisitions) to be consistent with IRPs, there are no states in which this requirement holds absolutely. Changing circumstances, forecast assumptions, and strategic decisions may cause a utility to deviate substantially from an IRP. Thus, IRPs are not generally considered enforceable. CPCN, including preapproval processes, carries the expectation that a specific action will be taken. However, the outcome of a CPCN process is usually permission, not a requirement, to proceed. In April 2011, for example, Louisville Gas and Electric and Kentucky Utilities filed a joint IRP which included the need for new gas-fired combined cycle generating units in 2016, 2018, and 2025 (LGE 2011a). Later that year, the Public Utilities Commission approved the companies' application for CPCN to construct one of those combined cycle units at the Cane Run generating station (LGE 2011b). The utilities began construction of the unit, and reported in their 2014 IRP that it is scheduled to come online in 2015 (LGE 2014).

In some cases, CPCN may be granted with conditions; in particular, CPCNs that are a result of settlement, rather than litigation, may carry requirements from other parties, such as a minimum purchase of renewable energy or an energy efficiency target. For example, in 2014, the Public Service Company of New Mexico offered a settlement by which the affected utility would acquire incremental renewable energy to attenuate opposition to a CPCN request (NM PRC 2010). Figure 7.1.2 provides a flow chart of IRP and CPCN long-term electricity resource planning, illustrating the differences in how the results of these processes are applied.

Figure 7.1.2: Flow Chart of Long-Term Planning Processes



Source: Synapse 2013

State Examples

Nevada IRP

Under section 704 of the Nevada Revised Statutes, Nevada requires that each electric utility submit an IRP every 3 years. The state PUC prescribes the plan's contents, which must include, but are not limited to, the methods used to forecast electric demand and determine the best combination of supply- and demand-side resources to meet consumer needs. Utility plans must include: 1) an energy efficiency program for residential customers with new solar thermal energy sources; 2) a comparison of several scenarios that look at different combinations of supply- and demand-side resources, at least one of which much be a low carbon intensity scenario; and 3) a plan for expanding transmission facilities to serve PUC-designated renewable energy zones. After a utility has submitted its plan, a hearing shall be convened to determine the plan's adequacy. The PUC determines whether the plan adequately forecasts load and energy efficiency savings, and whether it considers the benefits of improvements in efficiency, power pooling, power purchases, renewable generation including cogeneration, other types of generation facilities, and other transmission facilities. The PUC may give preference to resources that provide the greatest economic and environmental benefits to the state and provide the greatest opportunity for creating new jobs. After a utility has filed its plan, the PUC may accept the plan as filed or specify those areas of the plan that it finds to be inadequate. Utilities then have the opportunity to file an amendment to their resource plans.

Senate Bill No. 123 amended these statutes in 2013 to require that utilities also file a comprehensive emissions reduction and capacity replacement plan, reducing emissions from coal-fired electric generating plans and replacing that capacity with capacity from renewable facilities. The plan must provide for the retirement of 300 MW by the end of 2014, an additional 250 MW by the end of 2017, and an additional 250 MW by the end of 2019. Simultaneously, each utility must issue a request for proposals for 100 MW of renewable energy by 2014, an additional 100 MW by 2015, and an additional 100 MW by 2016. The utility must begin constructing an additional 50 MW of renewable energy to be owned by that utility before the end of 2017. These emissions reduction plans are subject to PUC review, and the PUC may accept the plan or recommend a modification or amendment if any portion of the plan is deemed inadequate.

Georgia Power Company IRP and CPCN

In 2011, Georgia Power submitted an application to decertify two coal units and authorize power purchase agreements, supported by an IRP. As an example of how different planning processes can work together, the Georgia PUC required the utility to update its IRP prior to allowing further expenditures at existing units. In 2013, Georgia Power submitted a revised IRP, expressly requesting further decertifications, demand-side management programs, fuel cost increases, and other approvals. The IRP became the basis for the Company's rate case filed later that year. In the rate case, many of the costs considered in the 2013 IRP were addressed through an environmental cost recovery rider, transforming the rate case into a pre-determination proceeding, similar to a CPCN.

Oregon IRP

In Oregon, investor-owned gas and electric utilities file individual least cost plans or IRPs with the PUC every 2 years. The plans, required since 1989, cover a 20-year period. The primary goal is to acquire resources at the least cost to the utility and ratepayers in a manner consistent with the public interest. These plans are expected to provide a reasonable balance between least cost and risk. By filing these plans, the utilities hope that in future proceedings the PUC will not reject, and prevent utilities from recouping, some of the costs associated with resource acquisition.

Connecticut IRP

Connecticut Public Act No. 11-80 requires the CT DEEP to develop a statewide IRP in conjunction with the Connecticut Energy Advisory Board and the state's electric distribution companies. After reviewing the state's energy and capacity needs, the CT DEEP must create a plan for procuring energy resources that seeks to minimize resource costs, maximize customer benefits, and lower the price of electricity over time. Energy resources include, but are not limited to, conventional and renewable generating facilities, energy efficiency, load management, demand response, CHP, DG, and other emerging technologies. Resource needs are to be met first with all available energy efficiency and demand reduction resources that are cost-effective, reliable, and feasible. The state IRP should include an assessment of: 1) energy and capacity requirements for the next 3, 5, and 10 years; 2) how best to eliminate demand growth; 3) how best to level the state's electric demand through reductions in peak demand and load shifting to off-peak periods; 4) the impact of current and proposed environmental standards; 5) any energy security or economic risks associated with energy resources; and 6) estimated lifetime costs and availability of energy resources.

The CT DEEP is required to hold a public hearing on the completed IRP and consider all written and oral comments on the proposed plan. The commissioner may approve or reject the plan with comments. The procurement manager of the Public Utilities Regulatory Authority will then develop and hold public hearings on a procurement plan in consultation with the electric distribution companies, ISO-NE, and the Connecticut Energy Advisory Board. Every 2 years, the CT DEEP must report to the General Assembly on progress toward plan implementation, as well as any recommendations about the process.

New Jersey Energy Master Plan

New Jersey state law requires an Energy Master Plan (EMP) to be revised and updated at least every 3 years to address the production, distribution, consumption, and conservation of energy in the state. The law requires the EMP to include both long-term objectives and interim measures consistent with and necessary for achieving the long-term objectives. The EMP considers the full scope of energy service delivery in the state, including energy sources that are regulated by the Board of Public Utilities (such as electric and natural gas IOUs) and those that are not (NJ EMP n.d.).

Like the previous EMP in 2008, the 2011 EMP recognized "what the State can do directly to affect the reliability and cost of energy; what the State is constrained to do indirectly to influence the decisions of PJM, the FERC, and power plant owners and developers; and what factors are outside the State's control" (NJ EMP 2011). While the goals, targets, and policies put forth in the plans are not, by themselves, enforceable in practice, the plans serve as guidance for narrower resource planning processes. For example, policy direction and targets from the plans are fed into the process for determining funding levels for the state's energy efficiency and renewable energy incentive programs.

Northwest Power and Conservation Council

The Sixth Northwest Conservation and Electric Power Plan was issued in February 2010, making it the most recent plan released by the NWPCC. The plan is intended to mitigate risks that stem from uncertainties such as climate change policy, fuel prices, and economic growth. The Sixth Plan includes recommendations to ensure the reliability and efficiency of the power system.

Improving energy efficiency is a top priority because it is predicted to be the least financially risky resource, has no ongoing fuel costs or dependence on foreign imports, and reduces demand on the Northwest's hydroelectricity industry while supporting reliable and affordable electricity service. If implemented, these improvements could fulfill 85 percent of the region's increased energy needs over the next 20 years, as well as defer investments from what are currently expensive low-carbon technologies or less clean energy resources (NWPCC 2010b). The NWPCC has also illustrated energy efficiency's sustainability over time by reducing electricity demand by an average of 3,900 MW between 1978 and 2008. In addition, they have identified 6,000 MW of available new efficiency, demonstrating the future viability of this resource (NWPCC 2010a).

Additional recommendations include developing cost-effective renewable energy, such as wind. The plan advises improving power system operations to incorporate new wind energy as well as enhance its efficiency and flexibility. The plan also encourages the construction of natural gas-fired plants to meet local needs, reduce dependence on coal, ensure sufficient backup power, and meet carbon-reduction targets. Lastly, the plan recommends researching the potential of new technologies, such as smart-grid technology or carbon sequestration, for future development and long-term stability of the region's power system (NWPCC 2010b).

What States Can Do

Action Steps for States

Most states already have some form of electricity resource planning processes. These states may be able to take action to ensure that energy efficiency, renewable energy, and CHP are consistently considered along with other resource options. Actions for states that already have electricity resource planning processes include:

- Remove barriers to fair consideration of available energy efficiency resources by using third-party energy efficiency potential studies and mandating all cost-effective energy efficiency in planning.
- Update key assumptions for renewable energy so that values for current and future capacity availability and costs reflect current market conditions.
- Require utilities to assume both existing and reasonably expected future EERS and RPS policies, as well as environmental regulations, in their electricity resource modeling.
- Ensure that the resource planning process is tied to investment decisions or other enforceable actions.
- Leverage existing knowledge from state utility and environmental regulators.
- Increase transparency in planning processes—for example, by presuming that all information should be public unless demonstrated to be proprietary or protected business information.
- Promote meaningful stakeholder input, including input from consumer advocates and non-governmental organizations that promote energy efficiency, renewable energy, and CHP.

For states that do not yet have long-term electricity resource planning processes in place, state legislation can be used to direct the state PUC to require planning. For examples of IRP state statutes, see the information resources listed at the end of this section. DOE also offers grant funding and technical assistance to state governments, including energy offices and PUCs, to facilitate the sharing of state best practices and to conduct stakeholder processes that help establish electricity resource planning.[79]

[79] For more information on technical assistance available through DOE, visit http://www.energy.gov/ta/state-local-and-tribal-technical-assistance-gateway. Funding opportunities available to assist states in electricity resource planning may be made available through the State Energy Program (http://energy.gov/eere/wipo/state-energy-program).

States can also work through their state legislatures and/or utility regulators to establish new electricity resource planning processes or make statutory changes that remove barriers to fair consideration of all resource options.

Increasing State Agency Coordination in Electricity Resource Planning

Energy planning can affect the work of a variety of state government agencies, and many of these agencies can provide valuable input to the planning process. Thus, many states have found benefits in fostering more interagency communication and collaboration.

A useful first step is to determine who plays a role and what mechanisms currently exist for interagency collaboration. As the *Participants* section on page 7-18 explains, state agencies may already participate in planning as regulators (e.g., PUCs in rate-based cases such as IRP, CPCN, and default service cases; air regulators in permitting) or as intervenors or stakeholders (e.g., a consumer advocate or attorney general's office representing ratepayers, or a Department of Energy representing state policy).

In one example of fostering coordination, the Commonwealth of Massachusetts brought its environmental and energy offices together under the Executive Office of Energy and Environmental Affairs in 2007. However, even without combining agencies, utility and environmental regulators can find many opportunities to coordinate. For example, PUC staff can alert environmental managers about ongoing planning processes and engage them to vet long-term environmental outcomes; environmental regulators can similarly alert PUC staff and ratepayer advocates about air and water permit applications. Such coordination can be mutually beneficial to both agencies as decisions made by one state entity can have significant implications on other regulatory bodies. In some cases, utilities pursue air or construction permits prior to pursuing a CPCN or preapproval, thus creating a situation in which long-term planning is necessarily compressed by permit deadlines, or constraining potential outcomes for utility regulators. In the inverse situation, utility regulators may not be aware of impending, or even ongoing, environmental regulatory requirements that pose financial risks or costs. Utility regulatory decisions may have substantial effects on a state's ability to pursue energy efficiency, renewable energy, and CHP alternatives.

Information Resources

Resources on Integrating Energy Efficiency, Renewable Energy, and CHP into Electricity Resource Planning

Title/Description	URL Address
Resource Planning Model: An Integrated Resource Planning and Dispatch Tool for Regional Electric Systems. This 2013 report for NREL introduces a capacity expansion model, the Resource Planning Model, with high spatial and temporal resolution that can be used for mid- and long-term scenario planning of regional power systems.	http://www.nrel.gov/docs/fy13osti/56723.pdf
Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures. This 2011 report for the State and Local Energy Efficiency Action Network summarizes the benefits of IRP processes as a mechanism to encourage cost-effective energy efficiency, and provides best practices on how to develop IRPs and other similar planning processes that promote energy efficiency.	https://www4.eere.energy.gov/seeaction/sites/default/files/pdfs/ratepayer_efficiency_irpportfoliomanagement.pdf
Energy Efficiency Participation in Electricity Capacity Markets: The US Experience. This 2014 paper summarizes the rules governing how efficiency resources participate in the ISO-NE and PJM capacity markets, the result of that participation, and lessons learned to date.	http://www.raponline.org/document/download/id/7303
Guide to Resource Planning with Energy Efficiency. This guide from the National Action Plan for Energy Efficiency, published in 2007, describes key issues, best practices, and main process steps for integrating energy efficiency into resource planning.	http://www.epa.gov/cleanenergy/documents/suca/resource_planning.pdf
Treatment of Solar Generation in Electric Utility Resource Planning. This 2013 technical report from NREL captures utility-provided information about how utilities approach long-range resource planning, methods and tools utilities use to conduct resource planning, and how solar technologies are considered in the resource planning process.	http://www.nrel.gov/docs/fy14osti/60047.pdf
Incorporating Energy Efficiency into Western Interconnection Transmission Planning. This 2014 report documents the energy efficiency-related analyses developed by Lawrence Berkeley National Laboratory for the Western Electricity Coordinating Council's Transmission Expansion Planning and Policy Committee 2011 and 2012 study cycles.	http://emp.lbl.gov/sites/all/files/lbnl-6578e.pdf
A Guidebook to Expanding the Role of Renewables in a Power Supply Portfolio. This 2004 report prepared for the American Public Power Association's Demonstration of Energy-Efficient Development Program describes a suggested process and analytic approach to aid utility managers in expanding the role of renewable resources in their energy supply portfolios.	http://apps2.eere.energy.gov/wind/windexchange/pdfs/power_supply_guidebook.pdf
Edison Electric Institute/Natural Resources Defense Council (EEI/NRDC) Joint Statement to State Utility Regulators. This February 2014 statement by the EEI and NRDC provides recommendations to utilities for innovative technologies that enhance grid performance while lowering emissions, including net metering and energy efficiency measures.	http://docs.nrdc.org/energy/files/ene_14021101a.pdf

Title/Description	URL Address
A Brief Survey of State Integrated Resource Planning Rules and Requirements. This 2011 document by Synapse Energy Economics, Inc., provides an overview of IRP rules in each state, as well as a general discussion of LTPP.	http://www.cleanskies.org/wp-content/uploads/2011/05/ACSF_IRP-Survey_Final_2011-04-28.pdf

Additional Resources Related to Electricity Resource Planning

Title/Description	URL Address
Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans. This 2013 report by Synapse Energy Economics, Inc., provides utilities, commissions, and legislatures with IRP guidance by offering best practice examples.	http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-06.RAP_.Best-Practices-in-IRP.13-038.pdf
Integrated, Multi-pollutant Planning for Energy and Air Quality (IMPEAQ). This 2013 paper represents the Regulatory Assistance Project's (RAP's) early-stage effort to develop a model process that states, local agencies, and EPA can use to comprehensively and simultaneously reduce all air pollutants (criteria, toxic, and greenhouse gases). IMPEAQ adheres to integrated resource planning principles by trying to identify least cost pathways to reduce emissions.	http://www.raponline.org/document/download/id/6440
Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans. This 2013 report describes IRP requirements in three states that have recently updated their regulations governing the planning process, and it reviews the most recent resource plan from the largest utility in each of those states.	http://www.raponline.org/document/download/id/6608
Projecting EGU CO2 Emission Performance in State Plans This Technical Support Document to EPA's 2014 Clean Power Plan Proposal includes a discussion of modeling structures used in utility planning.	http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-projecting-egu-co2emission-performance.pdf
EPA Power Sector Modeling. This website provides information and documentation on EPA's application of the Integrated Planning Model (IPM) to analyze the impact of air emissions policies on the U.S. electric power sector.	http://www.epa.gov/powersectormodeling/
Assessment of Demand-Side Resources within the Eastern Interconnection. This 2013 guide, prepared for the Eastern Interconnection States' Planning Council and National Association of Regulatory Utility Commissioners, is an assessment of demand-side resources and their existing and forecasted deployments within the eastern United States. The guide was commissioned to improve understanding of how demand-side resources will affect the needs of future transmission development throughout the Eastern Interconnection.	http://communities.nrri.org/documents/68668/9f3dc4d3-485a-4d54-aad6-80964c932c5e
Utility Scenario Planning: "Always Acceptable" vs. the "Optimal" Solution. This paper describes the concept of Utility Scenario Planning, which is a tool similar to integrated resource planning in which utilities identify sharply different "scenarios" of the future and then seek to define a resource strategy that is most successful in addressing all of those potential futures.	http://www.nrri.org/documents/317330/c1f34184-faf6-4585-8d6f-04587d7da2f9
2013 Carbon Dioxide Price Forecast. This report provides a reasonable range of future price estimates for CO_2 for use in utility integrated resource planning and other electricity resource planning analyses.	http://www.synapse-energy.com/sites/default/files/SynapseReport.2013-11.0.2013-Carbon-Forecast.13-098.pdf

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A Brief Survey of State Integrated Resource Planning Rules and Requirements. This 2011 report, prepared for the American Clean Skies Foundation, provides an overview of state integrated resource planning rules and identifies for each state the planning horizon, frequency with which plans must be updated, and the resources required to be considered.	http://www.synapse-energy.com/sites/default/files/SynapseReport.2011-04.ACSF_.IRP-Survey.11-013.pdf
Portfolio Management: Design Principles and Strategies. This presentation, part of a 2003 portfolio management workshop hosted by RAP, provides background information and outlines design choices and strategies for effective portfolio management.	http://www.raponline.org/document/download/id/241
State Generation and Transmission Siting Directory. This EEI directory provides siting process summaries for Washington, D.C., and all 50 states.	http://www.eei.org/issuesandpolicy/transmission/Documents/State_Generation_Transmission_Siting_Directory.pdf

State IRP Statutes

State	Title/Description	URL Address
Arizona	Arizona Corporate Commission Decision No. 71722, in Docket No. RE-00000A-09-0249. June 3, 2010.	http://images.edocket.azcc.gov/docketpdf/0000112475.pdf
Arkansas	Arkansas PSC. Resource Planning Guidelines for Electric Utilities. Approved in Docket 06-028-R. January 4, 2007.	http://www.apscservices.info/pdf/06/06-028-r_57_1.pdf
Colorado	Colorado PUC. 4 CCR 723-3, Part 3: Rules Regulating Electric Utilities. Decision No. C10-1111. Docket No. 10R-214E. November 22, 2010.	https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=81364
Delaware	Delaware Electric Utility Retail Customer Supply Act of 2006. Delaware Code, Title 26, Chapter 10 Section 1007(c)(1)	http://delcode.delaware.gov/title26/c010/index.shtml
Georgia	Georgia Public Service Commission. General Rules. 515-3-4-.06 Integrated Resource Plan Filing Requirements and Procedures. Amended.	http://rules.sos.state.ga.us/docs/515/3/4/06.pdf
Hawai'i	Public Utilities Commission, State of Hawaii, A Framework for Integrated Resource Planning. March 9, 1992. Revised: March 14, 2011.	http://www.hawaiianelectric.com/vcmcontent/IntegratedResource/IRP/PDF/IRP_Framework_March_2011.pdf
Idaho	Idaho Public Utilities Commission Order No. 22299, in Case No. U-1500-165.	http://www.puc.idaho.gov/search/cases/electriccases.html
Indiana	Indiana Administrative Code 4-7-1: Guidelines for Integrated Resource Planning by an Electric Utility. New draft rules have been proposed in docket IURC RM 11-07, but are on hold due to the rulemaking moratorium currently in effect in Indiana.	http://www.in.gov/legislative/iac/title170.html (status updates for the IRP update rule making can be found here: http://www.in.gov/iurc/2673.htm)
Kentucky	Integrated Resource Planning by Electric Utilities. Relates to KRS Chapter 278.	http://www.lrc.ky.gov/kar/807/005/058.htm
Louisiana	Louisiana Public Service Commission Corrected General Order. Docket No. R-30021. Decided at the Commission's March 21, 2012, Business and Executive Session.	http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=95a4e806-45b4-4d5d-ae07-dd088a447363

State	Title/Description	URL Address
Minnesota	Resource Planning; Renewable Energy planning requirements: MN Statute §216B.2422. Utility planning requirements: MN Administrative Rules Chapter 7843. "Utility Resource Planning Process."	Statute available at: https://www.revisor.mn.gov/statutes/?id=216B.2422 Rule available at: https://www.revisor.mn.gov/rules/?id=7843
Missouri	Rules of Dept. of Economic Development. Division 240-PSC. Chapter 22—Electric Utility Resource Planning (4 CSR 240.22).	http://www.sos.mo.gov/adrules/csr/current/4csr/4c240-22.pdf
Montana	Montana's Integrated Least-Cost Resource Planning and Acquisition Act (§§ 69-3-1201-1206, Montana Code Annotated). For traditional utilities: Administrative Rules of Montana 38.5.2001-2016, adopted by the Montana PSC. Least Cost Planning – Electric Utilities. For restructured utilities: Administrative Rules of Montana 38.5.8201-8227, adopted by the Montana PSC. Default Electric Supplier Procurement Guidelines.	Code, Title 69: http://leg.mt.gov/bills/mca_toc/69_3_12.htm Rules, Chapter 38.5: http://www.mtrules.org/gateway/ChapterHome.asp?Chapter=38.5
Nebraska	Nebraska Revised Statute 66-1060.	http://nebraskalegislature.gov/laws/statutes.php?statute=66-1060
Nevada	Nevada Revised Statutes 704.741.	http://www.leg.state.nv.us/nrs/NRS-704.html
New Hampshire	Title XXXIV Public Utilities, Chapter 378: Rates and Charges, Section 38: Least Cost Energy Planning.	http://www.gencourt.state.nh.us/rsa/html/NHTOC/NHTOC-XXXIV-378.htm
New Mexico	New Mexico Administrative Code, Title 17, Chapter 7, Part 3. "Integrated Resource Plans for Electric Utilities.	http://164.64.110.239/nmac/parts/title17/17.007.0003.htm
North Carolina	North Carolina Utilities Commission Rule R08-60: Integrated Resource Planning and Filings.	http://ncrules.state.nc.us/ncac/title%2004%20-%20commerce/chapter%2011%20-%20utilities%20commission/04%20ncac%2011%20r08-60.pdf
North Dakota	North Dakota PSC Order issued on January 27, 1987 in Case No. 10,799. Amended on March 11, 1992 in Case No. PU- 399-91-689.	URL not available.
Oklahoma	Title 165: Oklahoma Corporation Commission. Chapter 35: Electric Utility Rules, Subchapter 37: Integrated Resource Planning.	http://www.occeweb.com/rules/Ch%2035%20Electric%20Rules%20eff%209-12-2014%20Searchable.pdf
Oregon	Oregon PUC Order No. 07-002, Entered January 8, 2007.	http://apps.puc.state.or.us/orders/2007ords/07-002.pdf
South Carolina	Established in: Public Service Commission of South Carolina Order No. 91-885 in Docket No. 87-223-E. October 21, 1991. Authority: South Carolina Code of Laws, Title 58, Chapter 37, Section 58-37-40.	PSC Order: http://dms.psc.sc.gov/pdf/orders/DF4FC4A9-EB41-2CB4-D44614AD02D02B8D.pdf SC Code: http://www.scstatehouse.gov/code/t58c037.php

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South Dakota	Utility plan requirement: South Dakota Legislature 1977, Ch. 390, § 23. Chapter 49-41B-3. Facility plan requirement: Administrative Rule Chapter 20:10:21, Energy Facility Plans.	Utility plan: http://legis.sd.gov/Statutes/Codified_Laws/DisplayStatute.aspx?Type=Statute&Statute=49-41B-3&cookieCheck=true Facility plan: http://legis.sd.gov/Rules/DisplayRule.aspx?Rule=20:10:21&cookieCheck=true
Utah	Report and Order on Standards and Guidelines. Docket No. 90-2035-01. In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp. Issued June 18, 1992.	http://www.airquality.utah.gov/Public-Interest/Current-Issues/Regionalhazesip/RegionalHazeTSDdocs/Utah_PSC_Integrated_Planning_Rules.pdf
Vermont	Vermont Statutes, Title 30 (30 V.S.A.), Chapter 5, Sub-chapter 1, Section 218c, Least Cost Integrated Planning.	http://legislature.vermont.gov/statutes/section/30/005/00218c
Virginia	Definitions (Code of Virginia § 56-597). Contents of Integrated Resource Plans (Code of Virginia § 56-598). Integrated Resource Plan Required (Code of Virginia § 56-599).	Section 597: http://leg1.state.va.us/cgi-bin/legp504.exe?000+cod+56-597 Section 598: http://leg1.state.va.us/cgi-bin/legp504.exe?000+cod+56-598 Section 599: http://leg1.state.va.us/cgi-bin/legp504.exe?000+cod+56-599
Washington	Washington Administrative Code 480-100-238: Integrated Resource Planning.	http://apps.leg.wa.gov/wac/default.aspx?cite=480-100-238
Wyoming	Wyoming Public Service Commission Rule 253 (submitted July 22, 2009), and associated Guidelines for Staff Review.	Rule: http://legisweb.state.wy.us/ARULES/2009/AR09-043.htm Guidelines: http://psc.state.wy.us/htdocs/electric/ElectricIRPGuidelines7-10.pdf

State CPCN Rules and Statutes

State	Title/Description	URL Address
Alabama	Certificate of Convenience and Necessity - When Required; Application; Issuance (ALA Code § 37-4-28).	http://codes.lp.findlaw.com/alcode/37/4/1/37-4-28
Arizona	Compliance by Utility; Commission Order (Arizona State Legislature Title 40-360.07).	http://www.azleg.state.az.us/FormatDocument.asp?inDoc=/ars/40/00360-07.htm&Title=40&DocType=ARS
Arkansas	City of Paragould v. Arkansas Utilities Co. (70 F.2d 530).	http://leagle.com/decision/193460070F2d530_1412.xml/CITY%20OF%20PARAGOULD%20v.%20ARKANSAS%20UTILITIES%20CO
Colorado	Colorado Public Utilities Commission: Rules Regulating Electric Utilities (4 CCR 723-3, §3102)	http://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=5738&fileName=4%20CCR%20723-3
Connecticut	Certificate of Environmental Compatibility and Public Need. Transfer. Amendment. Excepted Matters. Waiver (CT Gen Stat § 16-50k).	http://law.justia.com/codes/connecticut/2012/title-16/chapter-277a/section-16-50k

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Florida	Environmental Cost Recovery (Florida Statute 366.8255).	http://www.leg.state.fl.us/Statutes/index.cfm?App_mode=Display_Statute&Search_String=&URL=0300-0399/0366/Sections/0366.8255.html
Georgia	Actions Prohibited Without a Certificate of Public Convenience and Necessity (O.C.G.A. 46-3A-3).	http://law.justia.com/codes/georgia/2010/title-46/chapter-3a/46-3a-3
Idaho	Certificate of Convenience and Necessity (Idaho Statute 61-526.	http://www.legislature.idaho.gov/idstat/Title61/T61CH5SECT61-526.htm
Indiana	Necessity for Certification (Ind. Code §8-1-8.5-2)	http://codes.lp.findlaw.com/incode/8/1/8.5/8-1-8.5-2
Iowa	Electric Power Generation and Transmission (Iowa Code 476A).	http://coolice.legis.iowa.gov/cool-ice/default.asp?category=billinfo&service=iowacode&ga=83&input=476A
Kansas	Electric Public Utilities; Power, Authority, and Jurisdiction of State Corporation Commission (Kansas Statute 66-101). *Applies only to nuclear generation.*	http://www.kslegislature.org/li/b2015_16/statute/066_000_0000_chapter/066_001_0000_article/066_001_0001_section/066_001_0001_k/
Kentucky	Certificate of Convenience and Necessity Required for Construction Provision of Utility Service or of Utility–Exceptions–Approval Required for Acquisition or Transfer of Ownership–Public Hearing on Proposed Transmission Line mission–Severability of Provisions (Kentucky Statute 278.020).	http://www.lrc.ky.gov/Statutes/statute.aspx?id=14042
Maryland	Article – Public Utilities (§ 7-207).	http://mgaleg.maryland.gov/webmga/frmstatutestext.aspx?pid=&tab=subject5&stab=&ys=2015rs&article=gpu&section=7-207&ext=html&session=2015rs
Minnesota	Certificate of Need for Large Energy Facility (Minnesota Statute 216B.243).	https://www.revisor.mn.gov/statutes/?id=216B.243
Mississippi	Certificate of Public Convenience and Necessity Required; Exceptions; Complaints Prompting Hearing As to Adequacy of Service (MS Code § 77-3-11).	http://law.justia.com/codes/mississippi/2013/title-77/chapter-3/article-1/section-77-3-11/
Nebraska	Electric Generation Facilities and Transmission Lines; Approval or Denial of Application; Findings Required; Regional Line or Facilities; Additional Consideration (Nebraska Revised Statute 70-1014).	http://nebraskalegislature.gov/laws/statutes.php?statute=70-1014
Nevada	Specific Requirements for Electric Companies (NAC 703.185).	http://www.leg.state.nv.us/nac/NAC-703.html
New Mexico	New Construction; Ratemaking Principles (NM Stat § 62-9-1)	http://law.justia.com/codes/new-mexico/2011/chapter62/article9/section62-9-1

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New York	Article 10: Siting of Major Electric Generating Facilities.	http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/d12e078bf7a746ff85257a70004ef402/$FILE/Article10LawText%20.pdf
North Carolina	Certificate for Construction of Generating Facility; Analysis of Long-Range Needs for Expansion of Facilities; Ongoing Review of Construction Costs; Inclusion of Approved Construction Costs in Rates (G.S. § 62-110.1).	http://www.ncga.state.nc.us/EnactedLegislation/Statutes/HTML/BySection/Chapter_62/GS_62-110.1.html
North Dakota	Chapter 49-03: Electric Utility Franchise.	http://www.legis.nd.gov/cencode/t49c03.pdf?20141029133026
Ohio	Basis for Decision Granting or Denying Certificate (Ohio Revised Code 4906.10).	http://codes.ohio.gov/orc/4906.10
South Carolina	Utility Facility Siting and Environmental Protection Act (Title 58-33).	http://www.scstatehouse.gov/code/t58c033.php
West Virginia	Requirements for Certificate of Public Convenience and Necessity (West Virginia Code § 24-2-11).	http://www.legis.state.wv.us/wvcode/ChapterEntire.cfm?chap=24&art=2&section=11
Wisconsin	Regulation of Public Utilities (Wisconsin Statute 196).	http://docs.legis.wisconsin.gov/statutes/statutes/196.pdf
Wyoming	Certificate of Convenience and Necessity; Hearings (WY Stat § 37-2-205).	http://law.justia.com/codes/wyoming/2013/title-37/chapter-2/article-2/section-37-2-205/

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7.2 Policies That Sustain Utility Financial Health

Policy Description and Objective

Summary

Although aggressive energy efficiency and clean distributed generation programs help utilities diversify their portfolio, lower costs, and meet customer needs, some utilities may face important financial disincentives to adopting these programs under existing state regulatory policies. State regulators can establish or reinforce several policies to help curb these disincentives, including addressing the throughput incentive, ensuring program cost recovery, and defining shareholder performance incentives.

Public utility commissions (PUCs) in leading states are refining traditional utility policies to better align the utility financial interest with state and customer interest in affordable, reliable electricity service that minimizes environmental impacts.

As part of their business model, utilities take on financial commitments and incur risks in support of infrastructure investments and procurement plans (see Section 7.1, "Electricity Resource Planning and Procurement"). If the state PUC finds in a rate case or otherwise that such costs and risks are prudent, the costs are recovered in customer rates. Investor-owned utilities also need to remain profitable to their shareholders; their failure to do so can affect their stock price and bond ratings, as well as the cost of capital for future investments made on behalf of customers.

Traditional regulatory approaches link the recovery of utility investment and operating costs to the volume of electricity (kilowatt-hours [kWh]) sold to customers. Most retail rates are "volumetric," meaning that fixed and variable costs are recovered incrementally for each unit of energy sold. This creates an incentive to maximize the volume of sales across the wire (the "throughput" incentive) and a disincentive to invest in energy efficiency, distributed renewable energy, or combined heat and power (CHP), all of which reduce sales volume.[80] Decoupling revenue from sales volumes, ensuring program cost recovery, and providing shareholder incentives linked to program performance can help "level the playing field" for utility resource investments by creating an economically based comparison between supply- and demand-side resource alternatives that can yield a lower cost, cleaner, and more reliable energy system.

Objective

The objective of these policies is to align utilities' financial interests with state policy goals of advancing energy efficiency, distributed renewable energy, and CHP. Policies can provide complementary cost recovery and performance incentives for well-run and well-performing energy efficiency and distributed generation (DG) installation and promotion, as well as address potential financial disincentives utilities may face by eliminating or minimizing the throughput incentive embedded in traditional ratemaking.

Benefits

As part of a broader suite of energy efficiency, renewable energy, and CHP policies, well-designed financial incentive structures for utilities can encourage them to actively support these demand-side resources. States with existing policies to support the utility's financial health, such as cost recovery, revenue decoupling, and

[80] The effect of this linkage is exacerbated in the case of distribution-only utilities, as the revenue impact of electricity sales reduction is disproportionately larger for utilities without generation resources.

shareholder incentives, have the highest per capita investment in energy efficiency programs.[81] Encouraging the effective delivery of cost-effective energy efficiency and clean DG resources reduces a utility's need to expand existing facilities or to build more expensive, new central station power plants or transmission and distribution infrastructure, thus maximizing the value of a utility's existing gas or electric capacity. Energy efficiency and clean DG programs can also lower overall electric system costs and customer bills, among other benefits (RAP 2013).

Background on Utility Incentive Structures

The majority of electric utility costs are for capital-intensive equipment such as wires, poles, transformers, and generators. State PUCs determine how these costs may be recovered through proceedings known as rate cases. Utilities recover most of these fixed costs based on the volume of energy they sell. As a result, between rate cases, utilities have an incentive to encourage higher electricity sales (relative to forecast levels) in order to maximize how much electricity flows across their wires. This ensures recovery of fixed costs and maximizes allowable earnings; however, it also creates a disincentive for investing in energy efficiency or DG during the time between rate cases. In some states, regular (usually quarterly) adjustments, often known as fuel adjustment clauses, ensure recovery of variable costs, such as those for fuel. These clauses create an even greater disincentive for investing in energy efficiency.

Ratemaking could address this disincentive, for example, by allowing more frequent true-ups to rates to reflect actual sales and actual fixed cost revenue requirements. Another option is to shift a greater portion of fixed costs out of variable per-kWh charges into fixed customer charges. In both cases, this disincentive would be removed or minimized. However, energy efficiency options would only be able to better compete with alternative supply options in the frequent true-up case. A simplified illustration of this decoupling rate effect is shown in Table 7.2.1.

Separate, supplemental shareholder incentive policies, such as performance-based return on equity guarantees, could then operate more effectively without the disincentive that standard ratemaking practices otherwise impose on utilities. Frequent true-ups and shareholder incentives are more desirable than charging customers a high fixed

Table 7.2.1: Simplified Illustration of Decoupling Rate Effect

Rates and fixed cost recovery during initial period			
	Sales at Forecast	**Sales Below Forecast**	**Sales Above Forecast**
Sales Forecast	100 kWh		
Fixed Cost[a]	$6.00		
Variable Cost[b]	$0.04 per kWh		
Total Variable Cost	$4.00	$3.80	$4.20
Total Costs [Fixed + Variable]	$10.00	$9.80	$10.20
Authorized Rate [Costs Sales Forecast]	$0.100 per kWh		
Actual Sales	100 kWh	95 kWh	105 kWh
Actual Revenues	$10.00	$9.50	$10.50
Fixed Cost Recovery [Revenue - Cost]	Even $0.00	Under ($0.30)	Over $0.30
Rates in next period after decoupling true up			
	Sales at Forecast	**Sales Below Forecast**	**Sales Above Forecast**
Sales Forecast[c]	100 kWh		
Total Costs[c]	$10.00		
Revenue Requirement [Total Costs - Fixed Cost Recovery]	$10.00	$10.30	$9.70
New Authorized Rate [Revenue Requirement Sales Forecast]	$0.100 per kWh	$0.103 per kWh	$0.097 per kWh

[a] Fixed costs include return on rate base.
[b] Variable costs include operating costs of power plants.
[c] Assumes values from initial period for illustrative purposes.

Sources: NRDC 2004; PG&E 2003

[81] In 2010, seven of the 10 states with the highest per capita investment in electric energy efficiency programs, as well as eight of the 10 states with the highest per capita investment in natural gas energy efficiency programs, had decoupling in place or had adopted decoupling as state policy (NRDC 2012).

charge each month because they provide more flexibility for addressing differences in short- and long-term costs. A high monthly customer charge can also diminish customers' incentives for energy efficiency and onsite generation.

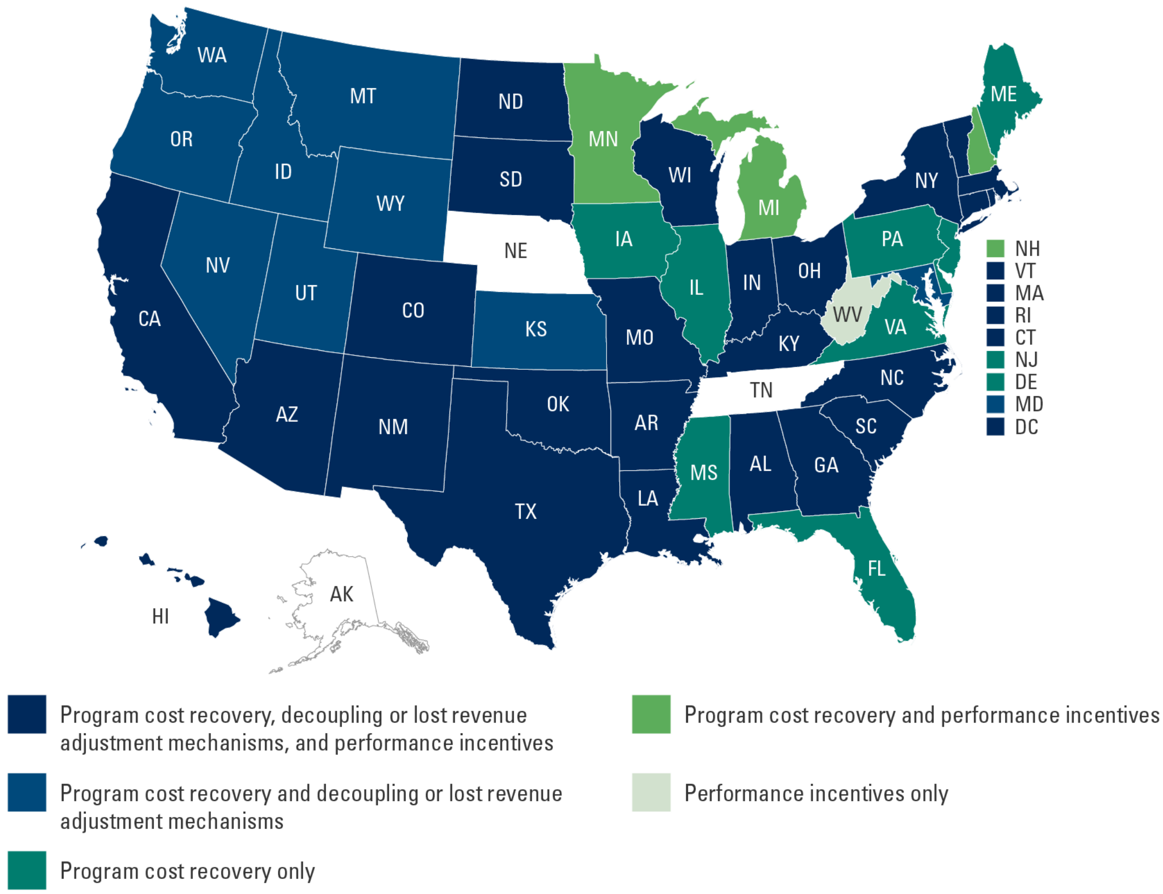
States with Utility Incentive Policies for Demand-Side Resources

States have developed three policies to level the playing field for demand-side resources through improved utility rate design:

- *Remove disincentives*. Some states have removed structures that discourage energy efficiency and clean DG implementation using revenue decoupling methods that seek to break the link between revenues and sales volumes. Some have alternatively established lost revenue recovery policies that are designed to recover lost margins for utilities as sales fall due to the success of energy efficiency programs. These two mechanisms can have significantly different effects and thus deserve careful consideration.
- *Recover costs.* Many states have given utilities a reasonable opportunity to recover energy efficiency and clean DG program implementation costs by incorporating program costs into utility base rates, providing riders or surcharges on bills, or establishing balancing accounts to prevent under-recovery of expenses. Cost recovery alone, however, does not remove the financial disincentive needed to further expand a utility's commitment to maximizing energy efficiency and clean DG.
- *Reward performance.* Some states have created shareholder incentives for implementing high-performance energy efficiency and, less frequently, clean DG programs. These incentives usually take the form of savings performance targets—in which incentives are paid when a utility achieves some fraction of proposed energy savings—or shared savings policies, in which utilities are compensated when they can demonstrate that energy efficiency programs resulted in net benefits (calculated as program costs netted against avoided supply-side costs) for ratepayers. In the past, states have implemented a bonus rate of return policy, in which utilities are allowed an increased return on investment for energy efficiency investments if the programs demonstrate measured or verified success; however, the bonus rate of return is rarely used now.

States with these three approaches, especially those with all three policies, have utilities supportive of policies to encourage demand-side energy efficiency, renewable energy, and CHP. Most states have had or are reviewing at least one of these forms of decoupling and incentive policy. Figure 7.2.1 shows the status of state implementation of financial incentive policies as of 2014.

Figure 7.2.1: Electric Utility Regulatory Financial Incentive Policies by State, 2014



Note: The sources update state status on a rolling basis, so this map reflects policies in place as of late 2013 to mid-2014, depending on the state. This map does not include states with pending legislation. As of September 2014, Delaware, Mississippi, and Virginia had pending decoupling or lost revenue adjustment mechanism legislation. Mississippi and Montana had pending performance incentive legislation.

Sources: ACEEE 2014; Edison Foundation 2013

Remove Disincentives through Decoupling or Lost Revenue Adjustment Policies

Traditional electric and gas utility ratemaking policies have caused financial disincentives for utilities to support energy efficiency and distributed renewable energy. This misalignment can be remedied through policies that decouple utility revenues from sales or lost revenue adjustment mechanisms (LRAMs).

Decoupling is an alternative means of eliminating lost revenues that might otherwise occur with energy efficiency and DG resource implementation. It is a variation of more conventional performance-based ratemaking (PBR). Under conventional ratemaking, a utility’s rates are fixed until the next rate case occurs at an undetermined future point in time. Under conventional PBR, a utility’s rates are typically set for a predetermined number of years (e.g., 5 years). This type of PBR is referred to as a “price cap” and is intended to provide utilities with a direct incentive to lower cost (and thereby increase profits) during the term of the price cap.

Decoupling is a variation of conventional PBR, and it is sometimes referred to as a particular form of "revenue cap." Under this approach, a utility's *revenues* are fixed for a specific term, in order to match the amount of anticipated costs incurred plus an appropriate profit. Alternatively, a utility's revenues per customer could be fixed, or some other revenue adjustment system can be used, thus providing an automatic adjustment to revenues. If the utility can reduce its costs during the term through energy efficiency, DG, or other system efficiencies, it will be able to increase its profits. Furthermore, if a utility's sales are reduced by any means, including efficiency, DG, weather, or economic swings, under-collections will be recovered from customers and the utility's revenues will not be affected. The effect is symmetrical; unexpectedly higher sales and the resulting higher revenues will return money to customers. This approach eliminates the throughput incentive and does not require an accurate forecast of the amount of lost revenues associated with energy efficiency or DG. It does, however, result in the potential for rate or price variation, reflecting an adjustment to the relationship between total utility revenue requirements and total electricity or gas consumed by customers over the defined term. Such rate adjustments, or true-ups, are a fundamental aspect of the rate design resulting from decoupling profits from sales volumes.

LRAMs allow a utility to directly recoup the lost revenue associated with not selling additional units of energy due to the successful reduction of electricity consumption by energy efficiency or DG programs. The amount of lost revenue is typically estimated by multiplying the fixed portion of the utility's prices per kWh by the energy savings from energy efficiency programs or the energy generated from DG. This amount is then directly returned to the utility. Some states have adopted these policies, but experience has shown that LRAMs can result in utilities being allowed more lost revenues than the energy efficiency program actually saved. This is because the lost revenues are often based on projected savings. Furthermore, because utilities still earn increased profits on additional sales, this approach does not fully remove the throughput incentive, and it provides a disincentive for utilities to implement additional energy efficiency or to support independent energy efficiency activities. In summary, unlike other decoupling approaches, the LRAM approach provides limited incentives, does not fully address the throughput incentive, and does not influence efficient utility operations companywide.

Another approach, known generically as straight fixed variable (SFV) ratemaking, involves an alternative rate structure that allows utilities to recover a larger share of their fixed costs through fixed charges to their customers. Ordinarily, utilities recover a sizable portion of their fixed costs (e.g., generators, transformers, wires, and poles) through variable charges (i.e., charges per unit of energy consumed), while the monthly per-customer charge collects costs strictly associated with connecting customers to the system. In contrast, SFV rate structures allocate all current fixed costs to a per-customer charge that does not vary with consumption. Related alternatives use a consumption block structure, which allocates costs across several blocks of commodity consumption and typically places most or all of the fixed costs within the initial block.

SFV and similar rate designs can provide significant earnings stability for a utility in the short run. Like revenue decoupling, these alternative rate structures do not provide a direct incentive for utilities to encourage customers to invest in energy efficiency, distributed renewables, or CHP, but do reduce the throughput incentives that encourage utilities to promote increased sales. However, these alternative rate designs can create problems because fixed costs can be very high, and allocation of fixed charges may impose ability-to-pay issues on lower income customers and thus be seen as regressive. SFV designs also reduce a customer's incentive to undertake efficiency improvements because the associated bill savings will be reduced. Further variable charges under an SFV design may fall to levels below the cost of new supply resources, which could lead to increased supply costs if customers are motivated to consume more electricity under such a rate design.

Table 7.2.2 compares the pros and cons of decoupling and lost revenue recovery mechanisms, as well as alternative rate structures. As the table illustrates, decoupling appears to be the simplest and most comprehensive approach to aligning utility incentives with investment in energy efficiency. While it requires more effort to establish a complete decoupling policy, it avoids the downsides of lost revenue and SFV approaches.

Table 7.2.2: Comparison of Policies for Removing Disincentives to Energy Efficiency Investment

Policy	Pros	Cons
Revenue decoupling: Policy that sets the utility's revenues at a fixed amount for a specific term to match the amount of anticipated costs incurred plus an appropriate profit.	o Revenue decoupling weakens the link between a utility's sales and margin recovery. This reduces utility reluctance to promote energy efficiency, including building codes, appliance standards, and energy efficiency programs. o Through decoupling, the utility's revenues are stabilized and shielded from fluctuations in sales. Some have argued that this, in turn, might lower utility risk and cost of capital (CA Energy Consulting 2007; Delaware PSC 2007).[a] The degree of stabilization is a function of adjustments made for weather, economic growth, and other factors (some regulations do not adjust revenues for weather or economic growth-induced changes in sales).[b] o Decoupling does not require an energy efficiency program measurement and evaluation process to determine the level of under-recovery of fixed costs.[c] o Decoupling has low administrative costs relative to specific lost revenue recovery policies. o Decoupling reduces the need for frequent rate cases and corresponding regulatory costs. o States have experience implementing revenue decoupling over several years.	o Rates (and in the case of gas utilities, non-gas customer rates) can be more volatile between rate cases, although annual caps can be instituted (Graceful Systems 2012). o Where carrying charges are applied to balancing accounts, the accruals can grow quickly. o The need for frequent balancing or true-up requires regulatory resources; however PUC resources to implement decoupling are much less than those required to conduct more frequent rate cases. o
Lost revenue recovery mechanisms: Policy that allows a utility to recoup lost revenue associated with not selling additional units of energy.	o Removes disincentive to energy efficiency investment in approved programs caused by under-recovery of allowed revenues. o	o Does not remove the throughput incentive to increase sales. o Does not remove the disincentive to support other energy saving policies. o Complex to implement given the need for precise evaluation; will increase regulatory costs if it is closely monitored. o Proper recovery (no over- or under-recovery) depends on precise evaluation of program savings.

Table 7.2.2: Comparison of Policies for Removing Disincentives to Energy Efficiency Investment

Policy	Pros	Cons
Alternative rate structures: Policy that allows utilities to recover a larger share of their fixed costs through fixed charges to their customers.	o Removes the utility's incentive to promote increased sales. o May align better with principles of embedded cost-causation. o Administratively simple.	o May not align with cost-causation principles for utilities, especially in the long run. o Creates issues of income equity. o Movement to an SFV design significantly reduces customer incentives to reduce consumption by lowering variable charges. High fixed charges can also lead to customer disconnection from the electric grid.

[a] The design of the decoupling policy can address risk-shifting through the nature of the adjustments that are included. Some states have explicitly not included weather-related fluctuations in the decoupling policy (the utility continues to bear weather risk). In addition, recognizing that utility shareholder risk decreases with decoupling, some decoupling plans include provisions for capturing some of the risk reduction benefits for consumers.

[b] The impact of decoupling in eliminating the throughput incentives is lessened as the scope of the decoupling policy shrinks.
Note, however, that as the various determinants of sales, such as weather and economic activity, are excluded from the policy, the need for complex adjustment evaluation methods increases. In any case, an evaluation process should nevertheless be a part of the broader energy efficiency investment process.

Source: Derived from NAPEE 2007.

As an example, California's original decoupling policy, an Electric Rate Adjustment Mechanism (ERAM), was in place between 1982 and 1996 and was successful in reducing rate risk to customers and revenue risk to the major utility companies (LBNL 1993). California dropped its decoupling policy in 1996 when electric utility restructuring was initiated and retail competition was introduced. When competition did not deliver on its promise, California brought back a decoupling approach as part of a larger effort to reinvigorate utility-sponsored energy efficiency programs. Conversely, Minnesota tried a lost revenue approach and met strong customer opposition because there was no cap on the total amount of revenues that could be recovered.

While decoupling is a critical step in optimizing energy efficiency benefits, states have found that decoupling alone is insufficient.[82] Most states therefore add one or both related approaches: assurance for energy efficiency program cost recovery and shareholder/company performance incentives to reward utilities for maximizing energy efficiency investment where it is cost-effective. Furthermore, as stated above, states that seek aggressive energy efficiency and DG deployment typically have a suite of policies in place to drive utility investment, such as energy efficiency and renewable energy resource standards.

Program Cost Recovery

Appropriate opportunity for cost recovery is an important element of utility energy efficiency and clean DG programs and all other utility costs. The extent to which this is a real risk for utilities depends upon the ratemaking practices in each state. Nonetheless, the perception of the risk can be a significant barrier to utilities, regardless of how real it is. Under traditional ratemaking, utilities might be unable to collect any additional energy efficiency or DG expenses that are not already included in the rate base. Similarly, under a price cap form of PBR, utilities might be precluded from recovering new costs incurred between the periods

[82] For example, see Cadmus (2013).

when price caps are set. However, traditional ratemaking can nonetheless allow program cost recovery for well-performing energy efficiency or DG programs, if desired. If revenue caps are in place, well-performing program costs can be included as part of the overall revenue requirement in the same way that supply-side fixed costs are usually included in revenue requirements. If energy efficiency/DG programs do not meet minimum performance criteria, then these costs could be excluded from revenue requirements and would therefore not be passed on to ratepayers.

Regulatory mechanisms can be used to overcome program cost recovery concerns. These mechanisms assure utilities that investments in cost-effective energy efficiency and DG resources will be recovered in rates, independent of the form of ratemaking in place. Under traditional ratemaking, an energy efficiency or DG surcharge could be included in rates and adjusted periodically to reflect actual costs incurred. Under a price cap form of PBR, energy efficiency and DG costs could be excluded from the price cap and adjusted periodically to reflect actual costs incurred.

Many states with restructured electric industries have introduced a public benefits fund (PBF) that provides utilities with a fixed amount of funding for energy efficiency and DG, thus eliminating this barrier to utilities. For example, in 2005, the New York Public Service Commission (PSC) approved a proposal in a Consolidated Edison Company (Con Edison) rate case that included, among other demand-side measures, demand-side management (DSM) program cost recovery through a PBF. In New Hampshire, the state Public Utilities Commission (PUC) allocates funding to several approved, core energy efficiency programs administered by the state's utilities.

Shareholder/Company Performance Incentives

Under traditional regulation, utilities may perceive that energy efficiency or clean DG investment conflicts with their profit targets. However, states are finding that once the throughput incentive is addressed, utilities are more likely to look at cost-effective energy efficiency and clean DG as a potential profit center and an important resource alternative to meet future customer needs. Utilities earn a profit on approved capital investment for generators, wires, poles, transformers, etc. Incentive ratemaking can allow for greater profit levels on energy efficiency or DG resources, recognizing that many benefits to these resources, such as improved reliability or reduced emissions, are not otherwise explicitly accounted for.

States such as California, Massachusetts, and New Hampshire are using profit or shareholder incentives to make returns on energy efficiency and clean DG investments sufficient enough to support serious consideration when compared with conventional supply-side investments. While implementing such policies can be contentious, the intent is that with throughput incentives removed, utilities can be rewarded with incentives stemming from superior program performance. Such incentives include a higher rate of return on capital invested in energy efficiency and clean DG, or equivalent earnings bonus allowances. Rewards require performance; independent auditing of energy efficiency/DG program effectiveness can drive the level of incentive. The savings that result from choosing the most cost-effective resources over less economical resources can be shared between ratepayers and shareholders, giving ratepayers the benefits of wise resource use while rewarding management for the practices that allow these benefits to be secured.[83]

[83] The utility industry uses the term "shared savings" in several ways. Alternative meanings include, for example, the sharing of savings between an end-user and a contractor who installs energy efficiency measures. Throughout this *Guide to Action*, "shared savings" refers to shareholder/ratepayer sharing of benefits arising from implementation of cost-effective energy efficiency/DG programs that result in a utility obtaining economical energy efficiency/DG resources.

Implementing a package of incentive regulation initiatives might include: 1) stakeholder discussion of the issues, 2) state commission rulemaking or a related initiative proposing a change from traditional ratemaking, and 3) clear and comprehensive direction from the state commission establishing the explicit rate structure or pilot program structure to be put in place.

Designing Effective Utility Incentives for Demand-Side Resources

Participants

A number of stakeholders are typically included in the design of decoupling and incentive regulations:

- *State legislatures*. Utility regulation broadly affects all state residents and businesses. State energy policy is affected by and affects utility regulation. Legislation may be required to direct the regulatory commission to initiate an incentive regulation investigation or to remove barriers to elements like periodic resetting of rates without a comprehensive rate case. Legislative mandates can also provide funding and/or political support for incentive regulation initiatives. By the same token, legislative initiatives can limit the ability of utility commissions and utilities to institute or benefit from regulatory incentives that support energy efficiency and DG.
- *State PUCs*. State PUCs have the greatest responsibility to investigate and consider incentive regulations. Staff and commissioners oversee the stakeholder processes through which incentive regulation issues are discussed. PUCs may have specific statutory direction, or they may implement "common good" laws. PUCs are the ultimate issuers of directives implementing incentive regulation packages for regulated gas and electric utilities.
- *Consumer counsels/advocates*. Most states have a standing "Office of Peoples Counsel" or similar organization whose mission is to represent consumer interests in PUC and court proceedings. Typically staffed by attorneys and regulatory specialists, consumer advocate offices regularly intervene in rate cases and related proceedings to represent typical residential ratepayer interests.
- *State energy offices/executive agencies.* State policies on energy and environmental issues are often driven by executive agencies at the behest of governors' offices. If executive agency staff are aware of the linkages between utility regulatory and ratemaking policies, it may be more likely that executive agency energy goals can be fostered by successful utility energy efficiency and clean DG programs. Attaining state energy and environmental policy goals hinges in part on the extent to which incentive regulation efforts succeed.
- *Energy efficiency providers*. Energy efficiency providers have a stake in incentive regulation initiatives. In some states, they contract with utilities to provide energy efficiency program implementation. In other states, energy efficiency providers such as Vermont's "Efficiency Vermont" serve as the managing entity for delivering energy efficiency programs.
- *DG developers*. DG developers, like energy efficiency providers, are affected by any incentive regulation that reduces throughput incentives, as they are likely to be able to work more closely with utilities to target the locations that maximize the benefits that DG can bring by reducing distribution costs. DG developers can benefit from net metering and other policies that reduce barriers to cost recovery.[84]

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[84] See Section 7.3, "Interconnection and Net Metering Standards," and Section 7.4, "Customer Rates and Data Access," for more information.

- *Utilities*. Vertically integrated utilities and distribution or distribution-transmission-only utilities are affected to the greatest degree by incentive regulation, as their approved revenue collection mechanisms are at the heart of incentive regulation issues.
- *Environmental advocates*. Energy efficiency, distributed renewable energy, and CHP resources can provide low-cost environmental benefits, especially when targeted to locations requiring significant transmission and distribution investment. Environmental organizations can offer perspectives on using energy efficiency, distributed renewable energy, and CHP as alternatives to supply-side options.
- *Other organizations*. Other organizations, including local governments; third-party program administrators; and energy efficiency, distributed renewable energy, and CHP industry stakeholders, can provide cost-effectiveness information as well as perspectives on other complementary policies.

Best Practices: Designing Effective Incentive Regulations for Gas and Electric Utilities

The best practices identified below will help states develop effective incentive regulations to support implementation of cost-effective energy efficiency, distributed renewable energy, and CHP.

- Survey the current regulatory landscape in your state and neighboring states.
- Determine if and how energy efficiency, distributed renewable energy, and CHP are addressed in rate structures. In particular, determine if traditional ratemaking formulas exist. Do they create obstacles to promoting energy efficiency, distributed renewable energy, and CHP?
- Gather information about potential incentive rate designs for your state.
- Assemble key stakeholders and provide a forum for their input on utility incentive options.
- Clarify specific objectives and underlying rationale for motivating utility actions.
- Devise an implementation plan with specific timelines and objectives.

Interaction with Federal, Regional, and State Policies

Incentive regulation is closely intertwined with almost all state-level energy policy involving electric and gas utility service delivery, since it addresses the fundamental issue of establishing a means for a regulated utility provider to recover its costs. The following state policies will be affected by changing to a form of incentive regulation:

- *Resource portfolio standards.* As discussed in Section 4.1, energy efficiency resource standards (EERSs) set numerical, multiyear targets for total energy savings. EERSs drive efficiency investment and program planning from these top-down targets, often for periods of 5 to 10 years or more. Renewable portfolio standards, discussed further in Chapter 5, set targets for renewable electricity acquisition, which may include energy efficiency, distributed renewable energy, and CHP.
- *Electricity planning and procurement policies*. These are an important complement to utility incentives because they can provide vertically integrated utilities (through use of integrated resource planning) and distribution-only utilities (through use of portfolio management) with a long-term planning framework for identifying the quantity and type of energy efficiency, distributed renewable energy, and CHP resources to pursue.
- *PBFs.* Also known as system benefits charges, PBFs may eliminate the need for—or provide another way of addressing—cost recovery. PBF funding approaches are discussed in Section 4.2, "Energy Efficiency Programs."
- *PBR*. PBR includes a host of mechanisms that can help achieve regulatory objectives. Many are tied to specific elements of ratemaking, such as price caps (i.e., a ceiling on the per unit rate charged for energy), revenue caps (i.e., a ceiling on total revenue), or revenue per customer caps. Many states already use

energy efficiency performance rewards. Typically, all PBR mechanisms are established with the goal of rewarding utility performance that results in superior customer service, reliability, or other measured outcomes of utility company effort. Reducing the throughput disincentive is one important form of PBR, and if it is not addressed, the effectiveness of other aspects of PBR can be undermined.

Under federal stimulus legislation passed in 2009, state governors were required to notify the Secretary of Energy regarding their state's implementation of utility incentive policies in order to receive part of the Department of Energy's State Energy Program (SEP) $3.1 billion funding under the American Recovery and Reinvestment Act (ARRA) of 2009. States use SEP funding for a variety of programs, inclusive of energy efficiency and clean DG. Section 401 of ARRA required assurances from state governors that the state regulatory authority seeks to implement a "general policy that ensures that utility financial incentives are aligned with helping their customers use energy more efficiently and that provide timely cost recovery and a timely earnings opportunity for utilities."

Evaluation

Some states have begun to evaluate their decoupling activities to ensure program success (CA Energy Consulting 2013; Graceful Systems 2012). For example, independent evaluation of the Oregon initiative for Northwest Natural Gas included a summary of the program's intentions, recognition that deviations from forecast usage affects the amount of fixed costs recovered, and acknowledgement that partial rather than full decoupling was attained. The report stated that the program had reduced the "variability of distribution revenues" and "alter[ed] NW Natural's incentives to promote energy efficiency" (CA Energy Consulting 2005).

The following information is usually collected as part of the evaluation process to document additional energy efficiency, distributed renewable energy, and CHP; customer rate impacts; and changes to program spending that arise due to changes to regulatory structures:

- Utility energy efficiency, distributed renewable energy, and CHP program expenditure and savings information.
- Additional data on weather and economic conditions to control for factors influencing retail sales other than program actions.
- Rate changes occurring during the program, if any, such as those arising from use of a balancing mechanism.

State Examples

Numerous states previously addressed or are currently exploring electric and gas incentive policies. Experiments in incentive regulation occurred through the mid-1990s but were generally overtaken by events leading to various forms of restructuring. There is renewed interest in incentive regulation due to recognition that barriers to energy efficiency still exist, and utility efforts to secure energy efficiency, distributed renewable energy, and CHP benefits remain promising. States are looking to incentive policies to remove barriers in order to meet the cost-effective potential of clean energy resources.

Many states have had or are reviewing various forms of decoupling or incentive regulation, including performance incentive structures. The body of state experience continues to grow, and this summary section does not seek to address all of its complexities and implications. The following illustrative state examples are listed in the approximate order of the extent to which decoupling policies have been considered in the state.

California

California's rate policies are not new. Between 1983 and the mid-1990s, California's rate design included an ERAM, a decoupling policy that was the forerunner of today's policy and the model for balancing mechanisms implemented by other states during the early 1990s. The impact of the original ERAM on California ratepayers was positive, with a negligible effect on rates, and it led to reduced rate volatility. While certain issues have been contentious, California's experience helpfully illustrates one of the longest standing state policies in this area.

Beginning in 2004, California re-adopted a revenue balancing mechanism that applies between rate cases and removes the throughput incentive by allowing for rate adjustments based on actual electricity sales, rather than test-year forecast sales. The California Public Utilities Commission (CPUC) established this mechanism to conform to a 2001 law that dictated policy in this area, stating that forecasting errors should not lead to significant over- or under-collection of revenue. Currently, the revenue balancing mechanism is combined with performance incentives for energy efficiency targets.

California first implemented a shared-savings incentive mechanism in the 1990s. The CPUC authorized a 70 percent/30 percent ratepayer/shareholder split of the net benefits arising from implementation of energy efficiency measures in the 1994–1997 timeframe. This mechanism first awarded shareholder earnings bonuses based on measured program performance. Between 1998 and 2002, the performance incentive was changed to reward "market transformation" efforts by the utilities. These incentives were phased out after 2002 due to the state's overhaul of its energy efficiency policies. In 2012, the CPUC defined a new shareholder incentive mechanism known as the Energy Savings and Performance Incentive for investor-owned utilities. A subsequent ruling in September 2013 allocates incentive earnings among four categories, including energy efficiency resource savings. Incentives for energy efficiency resource savings are capped at 9 percent of program expenditures.

Websites:
http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Shareholder+Incentive+Mechanism.htm (Rulemaking 12-01-005)
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M076/K775/76775903.PDF (Decision 13-09-023)

New York

In the 1990s, the New York PSC experimented with several different types of PBR, including revenue-cap decoupling mechanisms for Rochester Gas and Electric, Niagara Mohawk Power, and Con Edison (Biewald et al. 1997). In 2005, the PSC approved a joint proposal from all the stakeholders in a Con Edison rate case that included significant increases in spending on DSM, an LRAM, DSM program cost recovery through a PBF, and shareholder performance incentives. An April 2007 PSC order mandated that all electric and gas utilities in New York file proposals for true-up-based decoupling mechanisms, and currently, all six major electric and all 10 major gas companies have revenue decoupling mechanisms in place. In 2008, the PSC established incentives for electric utility energy efficiency programs, in which utilities earn incentives or incur negative adjustments based on the extent to which they achieve energy savings targets. Goals are set annually.

In 2014, the PSC commenced its "Reforming the Energy Vision" (REV) initiative (Case 14-M-0101), which will examine the potential for major changes to the state's energy industry and regulatory practices. The initiative is primarily intended to increase the use and coordination of distributed energy resources. On February 29, 2015, the NY PSC issued an order adopting the REV policy framework and establishing an implementation plan. The PSC also plans to release a companion to this order, under Track Two of the REV initiative, to adopt ratemaking reforms inclusive of policies that align utilities' financial interests with REV's policy objectives (NY PSC 2015).

Websites:
http://www3.dps.ny.gov/W/PSCWeb.nsf/All/26BE8A93967E604785257CC40066B91A?OpenDocument (Case 14-M-0101—Reforming the Energy Vision)
http://media.corporate-ir.net/media_files/nys/ed/Three-YearRateplan-3-24-05.pdf (CASE 04-E-0572–Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service)

Nevada

Nevada's current incentive mechanisms for electric utilities originate from a 2009 bill, SB 358, which directed the Public Utilities Commission of Nevada (PUCN) to remove financial disincentives for energy efficiency faced by utilities. In 2010, the PUCN approved an LRAM for utilities, which allows them to recover lost revenues during annual DSM filings. As of July 2014, a docket (12-12030) was open to investigate another method besides lost revenue recovery to compensate utilities for providing DSM programs. The PUCN has also adopted rules permitting gas utilities to propose decoupling profits from sales through a revenue-per-customer system.

In May 2011, NV Energy, the parent company of Nevada Power and Sierra Pacific Power Companies, received the first approval from the PUCN for the recovery of lost revenues for an electric utility.

Websites:
http://www.leg.state.nv.us/75th2009/Reports/history.cfm?billname=SB358 (Bill SB 358)
http://pucweb1.state.nv.us/PUC2/DktDetail.aspx (Docket 12-12030)

Arizona

Arizona has recently undertaken regulatory efforts to address incentive regulation, although it does not have an explicit decoupling policy in place. Arizona utilities operate a variety of DSM programs, and the Arizona Corporation Commission (ACC) has approved both performance incentives and full and partial revenue decoupling mechanisms on a case-by-case basis for utilities. Arizona Public Service and Tucson Electric Power Company (TEP), the state's two largest investor-owned utilities, both have partial revenue decoupling mechanisms and performance incentives in place, and the ACC has approved a full revenue decoupling mechanism for Southwest Gas.

Websites:
http://images.edocket.azcc.gov/docketpdf/0000137042.pdf (Partial-revenue decoupling, Arizona Public Service, Docket No. E-01345A-11-0224)
http://images.edocket.azcc.gov/docketpdf/0000152708.pdf (Performance incentive, Arizona Public Service, ACC Decision 74406)
http://images.edocket.azcc.gov/docketpdf/0000146156.pdf (Partial-revenue decoupling, TEP, Docket No. E-01933A-12-0291)
http://images.edocket.azcc.gov/docketpdf/0000146156.pdf (Performance Incentive, TEP, ACC Decision 743912)

What States Can Do

States are leveling the playing field for demand-side resources through improved utility rate design by removing disincentives through decoupling, LRAMs, or alternative rate structures. These actions make it possible for utilities to recover their energy efficiency, distributed renewable energy, and CHP program costs, and/or provide shareholder and company performance incentives.

The following are key state roles:

- *Legislatures*. While legislative mandate is often not required to allow state commissions to investigate and implement incentive regulation reforms, legislatures can help provide the resources required by state commissions to effectively conduct such processes. Legislative mandates can also provide political support or initiate incentive regulation investigations if the commission is not doing so on its own.
- *Executive agencies.* Executive agencies can support state energy policy goals by recognizing the important role of regulatory reform in providing incentives to electric and gas utilities to increase energy efficiency, distributed renewable energy, and CHP efforts. Their support can be important to encourage utilities or regulators that are concerned about change.
- *State PUCs*. State regulatory commissions usually have the legal authority to initiate investigations into incentive regulation ratemaking, including decoupling. Commissions have the regulatory framework, institutional history, and technical expertise to examine the potential for decoupling and consider incentive ratemaking elements within the context of state law and policy. State commissions are often able to directly adopt appropriate incentive regulation mechanisms after adequate review and exploration of alternative mechanisms.

Action Steps for States

States can take the following steps to promote incentive regulation for clean energy, as well as overall customer quality and lower costs:

- Survey the current utility incentive structure to determine how costs are currently recovered, whether any energy efficiency programs and shareholder incentives are in place, and how energy efficiency, distributed renewable energy, and CHP costs are recovered.
- Review available policy mechanisms.
- Review historical experience in the relevant states.
- Identify stakeholders that could be important to the process.
- Consider establishing a working group to engage stakeholders.
- Open a docket on these issues.
- Resolve priorities, which will help guide selection of tools.
- Determine which incentive regulation tools might be appropriate.
- Engage commissioners and staff and find consensus solutions.

Information Resources

General Reports, Articles, and Websites about Utility Incentives for Demand-Side Resources

Title/Description	URL Address
State and Local Energy Efficiency Action Network (SEE Action): Ratepayer-Funded Efficiency through Regulatory Policy Working Group. This SEE Action Working Group has several initiatives that provide state utility regulators and stakeholders the tools and information on how to create utility motivations that will lead to a significant increase in energy efficiency. The Working Group has hosted regional regulatory policy exercises and issued several fact sheets and reports to share policy options and best practices across states.	https://www4.eere.energy.gov/seeaction/topic-category/ratepayer-funded-efficiency-through-regulatory-policy
American Council for an Energy-Efficient Economy (ACEEE). ACEEE has published several reports in this area: • Utility Initiatives: Alternative Business Models and Incentive Mechanisms – ACEEE Policy Brief, June 2014. • Making the Business Case for Energy Efficiency: Case Studies of Supportive Utility Regulation – ACEEE Report Number U133, December 2013. • Balancing Interests: A Review of Lost Revenue Adjustment Mechanisms for Utility Energy Efficiency Programs – ACEEE Report Number U114, September, 2011. • Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Initiatives – ACEEE Report Number U061, October 2006. • ACEEE's annual State Energy Efficiency Scorecards also contains information on regulatory incentives.	www.aceee.org http://www.aceee.org/files/pdf/policy-brief/decoupling-brief-0714.pdf http://aceee.org/research-report/u133 http://aceee.org/research-report/u114 http://www.aceee.org/research-report/u061 http://www.aceee.org/state-policy/scorecard
The Regulatory Assistance Project (RAP). RAP has published several reports on decoupling and financial incentives. The RAP Library allows users to search by both Decoupling/Utility Incentives and Cost Recovery within the Energy Efficiency/ Resource Planning Topic search. RAP resources include a summary of decoupling as implemented in six states.	http://www.raponline.org/search http://www.raponline.org/document/download/id/7209
Financial Analysis of Incentive Mechanisms to Promote Energy Efficiency: Case Study of a Prototypical Southwest Utility. A 2009 study published by Lawrence Berkeley National Laboratory. A primary goal of this modeling is to provide regulators and policy-makers with an analytic framework and tools that assess the financial impacts of alternative incentive approaches on utility shareholders and customers if energy efficiency is implemented under various utility operating, cost, and supply conditions.	http://emp.lbl.gov/publications/financial-analysis-incentive-mechanisms-promote-energy-efficiency-case-study-prototypic
National Action Plan for Energy Efficiency. This former public-private initiative that worked collaboratively across utilities, utility regulators, and other partner organizations published a paper titled, *Aligning Utility Incentives with Investment in Energy Efficiency*, in 2007 to provide a comprehensive overview of policy options for states.	http://www.epa.gov/eeactionplan http://www.epa.gov/cleanenergy/documents/suca/incentives.pdf
Database of State Incentives for Renewables and Efficiency (DSIRE). DSIRE is a comprehensive source of information on U.S. incentives and policies that support renewables and energy efficiency. DSIRE is currently operated by the N.C. Solar Center at N.C. State University, and funded by the U.S. Department of Energy.	http://dsireusa.org/

Title/Description	URL Address
Joint Statement of the American Gas Association and the Natural Resources Defense Council (NRDC) on Utility Incentives for Energy Efficiency. This statement identifies ways to promote both economic and environmental progress by removing barriers to natural gas distribution companies' investments in urgently needed and cost-effective resources and infrastructure.	http://www.naruc.org/Resolutions/GS%20Second%20Joint%20Statement.pdf
Edison Electric Institute/NRDC Joint Statement to State Utility Regulators. This statement includes a number of key recommendations, inclusive of utility incentives policy options.	http://docs.nrdc.org/energy/files/ene_14021101a.pdf
State Electric Efficiency Regulatory Frameworks. Published by The Edison Foundation Institute for Electric Innovation (IEI) in 2013. IEI is a not-for-profit membership organization consisting of investor-owned electric utilities that represent about 70 percent of the U.S. electric power industry.	http://www.edisonfoundation.net/iei/Documents/IEE_StateRegulatoryFrame_0713.pdf
The Effect of Energy Efficiency Programs on Electric Utility Revenue Requirements. Briefing released by the American Public Power Association as part of ARRA implementation. The briefing presents options for public power to address disincentives to increasing energy efficiency.	http://www.publicpower.org/files/PDFs/EffectofEnergyEfficiency.pdf
Link to All State Utility Commission Websites. This NARUC website provides links to all state utility commission sites.	http://www.naruc.org/commissions/

State and Regional Information on Incentive Regulation Efforts

State	Title/Description	URL Address
California	California Energy Commission (CEC). CEC website.	http://www.energy.ca.gov/
	Energy Action Plan II. California's implementation roadmap for its energy policies.	http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF
	California Public Utilities Commission. CPUC website.	http://www.cpuc.ca.gov/puc/
	Energy Efficiency Proceeding Activity. CPUC current rulemaking on energy efficiency policies.	http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Current+Proceeding+Activity.htm
	Energy Savings Goals for Program Year 2006 and Beyond. September 23, 2004, CPUC Decision establishing energy savings goals for energy efficiency.	http://www.cpuc.ca.gov/Published/Final_decision/40212.htm
	Energy Efficiency Portfolio Plans and Program Funding Levels for 2006–2008- Phase 1 Issues. September 22, 2005, CPUC Decision on energy efficiency spending in phase I.	http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/49859.htm
Colorado	House Bill 1147. Addresses funding and cost recovery policy for natural gas energy efficiency.	http://www.leg.state.co.us/clics/clics2012a/csl.nsf/fsbillcont/50727F4BF1602BC287257981007F5282?Open&file=1147_01.pdf

State	Title/Description	URL Address
Idaho	Idaho Power—Investigation of Financial Disincentives (Case No. IPC-E-04-15). Summarizes regulatory proceedings and workshop results regarding the Idaho Power Utilities Commission's investigation of financial disincentives to energy efficiency programs for Idaho Power.	http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE0415/ordnotc/20060306NOTICE_OF_APPLICATION_IPC.PDF
Maryland	Gas Commodity Fact Sheet. Maryland PUC, Gas Commodity Rate Structure reference.	http://webapp.psc.state.md.us/intranet/gas/gasCommodity_new.cfm
Mid-Atlantic Distributed Resources Initiative (MADRI)	Electric Utility Revenue Stability Adjustment Factor. Model rule being developed by MADRI to reduce a utility's throughput incentive.	http://sites.energetics.com/MADRI/regulatory_models.html
Oregon	Order No. 02-388. Oregon PUC order on Northwest Natural Gas Decoupling. This order reauthorized deferred accounting for costs associated with NW Natural Gas Company's conservation and energy efficiency programs.	http://apps.puc.state.or.us/orders/2002ords/02-388.pdf
Washington	Natural Gas Decoupling Investigation. Describes the Washington Utilities and Transportation Commission's actions to investigate decoupling policies to eliminate disincentives to gas conservation and energy efficiency programs.	http://www.wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/43eb29bd6e98d0e8882577d1007fea20!OpenDocument

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ACEEE. 2014. State and Local Policy Database. American Council for an Energy-Efficient Economy. Accessed September 2014.	http://database.aceee.org/
Biewald, B., T. Woolf, P. Bradford, P. Chernick, S. Geller, and J. Oppenheim. 1997. Performance-Based Regulation in a Restructured Electric Industry. Prepared for the National Association of Regulatory Utility Commissioners.	http://www.synapse-energy.com/sites/default/files/SynapseReport.1997-11.NARUC_.PBR-in-a-Restructured-Electricity-Industry..97-U02.pdf
CA Energy Consulting. 2005. A Review of Distribution Margin Normalization as Approved by the Oregon PUC for Northwest Natural. Christensen Associates Energy Consulting, LLC.	http://www.wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/59c3e4d9f57b530c882577230059cf34!OpenDocument
CA Energy Consulting. 2007. A Review of Natural Gas Decoupling Mechanisms and Alternative Methods for Addressing Utility Disincentives to Promote Conservation. Christensen Associates Energy Consulting, LLC.	http://www.psc.state.ut.us/utilities/gas/05docs/05057T01/6-1-0753572Exbt%206.1.doc
CA Energy Consulting. 2013. A Summary of Revenue Decoupling Evaluations. Christensen Associates Energy Consulting, LLC.	http://www.caenergy.com/summary-revenue-decoupling-evaluations/
Cadmus. 2013. DSM in the Rate Case: A Regulatory Model for Resource Parity Between Supply and Demand. Public Utilities Fortnightly. Cadmus Group, Inc.	http://www.cadmusgroup.com/wp-content/uploads/2013/01/1301-DSMRateCase-hires.pdf
Delaware PSC. 2007. PSC Regulation Docket No. 59. Delaware Public Service Commission.	http://depsc.delaware.gov/dockets/reg59/reg59.shtml

Title/Description	URL Address
Edison Foundation. 2013. State Electric Efficiency Regulatory Frameworks. Innovation Electricity Efficiency. The Edison Foundation Institute for Electric Innovation.	http://www.edisonfoundation.net/iei/Documents/IEE_StateRegulatoryFrame_0713.pdf
Graceful Systems. 2012. A Decade of Decoupling for U.S. Energy Utilities: Rate Impacts, Designs, and Observations. Graceful Systems, LLC.	http://switchboard.nrdc.org/blogs/rcavanagh/decouplingreportMorganfinal.pdf
LBNL. 1993. The Theory and Practice of Decoupling. Lawrence Berkeley National Laboratory.	http://eetd.lbl.gov/sites/all/files/publications/report-lbnl-34555.pdf
NAPEE. 2007. Aligning Utility Incentives with Investment in Energy Efficiency. National Action Plan for Energy Efficiency.	http://www.epa.gov/cleanenergy/documents/suca/incentives.pdf
NRDC. 2004. Do Electric-Resource Portfolio Managers Have an Inherent Conflict of Interest with Energy Efficiency? Natural Resources Defense Council.	http://aceee.org/files/proceedings/2004/data/papers/SS04_Panel5_Paper01.pdf
NY PSC. 2015. 14-M-0101: Reforming the Energy Vision (REV). New York Public Service Commission.	http://www3.dps.ny.gov/W/PSCWeb.nsf/All/26BE8A93967E604785257CC40066B91A?OpenDocument
NRDC. 2012. Removing Disincentives to Utility Energy Efficiency Efforts. Natural Resources Defense Council.	http://www.nrdc.org/energy/decoupling/files/decoupling-utility-energy.pdf
RAP. 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.	www.raponline.org/document/download/id/6739

7.3 Interconnection and Net Metering Standards

Policy Description and Objective

Summary

Standard interconnection and net metering rules for distributed generation (DG) systems, such as renewable energy and combined heat and power (CHP), are policies used by states to accelerate the development of clean energy supply. Grid-connected DG systems can meet some or all of their host's electricity needs. Renewable energy systems potentially offer reliable, but intermittent, zero emissions energy at or near the point of energy use. CHP offers an efficient, clean, and reliable approach to generating both power and thermal energy from a single fuel source by recovering the waste heat for another beneficial purpose (for more information about CHP, see Chapter 6, "Policy Considerations for Combined Heat and Power"). DG system requirements for grid connections are also important because they involve electrical system safety and reliability.

Interconnection standards are processes and technical requirements that govern how electric utilities will treat distributed generation systems that customers seek to connect to the electric grid.

Net metering is a method of compensating customers for electricity that they generate on site in excess of their own consumption—essentially giving them credit for the excess power they send back to the grid. Depending on individual state or utility rules, net excess generation may be credited to the customer's account or carried over to a future billing period.

Standard interconnection rules stem from state legislation that directs state public utility commissions (PUCs) to establish uniform processes and technical requirements for grid-connected electric generators. These rules address the type and size of systems; they also define required safeguards, grid upgrades, operating restrictions, and application procedures that system applicants must meet. In some states, municipally or cooperatively owned utilities may be exempt from state regulations. State interconnection rules typically address larger DG projects connecting to the distribution grid, whereas the Federal Energy Regulatory Commission (FERC) has jurisdiction over project interconnection at the transmission level.

State interconnection policies can sometimes create unintended barriers for DG projects. Although their impact on the utility grid is likely to be significantly lower, smaller scale DG systems in some states are often subject to the same, frequently lengthy interconnection procedures as larger systems. If interconnection procedures are excessive or expensive in proportion to the size of the project, they can overwhelm project costs to the point of making clean DG uneconomical.

State legislation is also used to require the development of standard net metering rules. Net metering policies allow DG systems to receive credit for electricity generated on site that is exported to the utility grid. In effect, customers can bank exported generation, usually on a billing cycle basis, to offset future electricity use that they would otherwise have to purchase from the utility. Net metering policies often rely on the use of a single bi-directional utility meter to measure, or "net" out, the use and flow of electricity to and from the electric grid. Net metering policies generally place several limitations on eligible onsite generators, including maximum system size restrictions and the period that customers can roll over net metering credit into the future (i.e., year-to-year).

Today, most states have existing interconnection and net metering policies in place. However, many of these policies could be improved to meet best-in-class practices. States may wish to consider evaluating their existing rules against model policies considered to represent best practices. See the information resources at the end of this section for links to some best practices.

States have found that standardized interconnection and net metering rules are important components of promoting clean DG and are often most successful when coupled with other policies and programs. Consequently, states generally promote clean DG through a suite of related policies, including standardizing interconnection and net metering rules, addressing utility rates for standby and exit fees, creating renewable portfolio standards (RPSs), and enacting other initiatives.[85]

Objective

A key objective of standard interconnection and net metering rules is to encourage the connection of clean DG systems, such as renewable energy and CHP, to the electric grid to obtain their benefits without compromising safety or system reliability.

Benefits

Standardized interconnection and net metering rules can support clean DG development by providing clear and reasonable requirements for connecting clean energy systems to the electric utility grid and for crediting onsite generation that DG systems export back to the grid. By developing standard interconnection and net metering requirements, states make progress toward leveling the playing field for clean DG relative to traditional central power generation. Standard interconnection rules can help reduce uncertainty and prevent excessive time delays and costs that small DG systems sometimes encounter when obtaining approval for grid connection.

The benefits of increasing the number of clean DG projects include reducing peak electrical demand on non-DG generators, increasing capacity, reducing the environmental impact of power generation, improving infrastructure resiliency, and avoiding energy losses along transmission and distribution lines. DG application in targeted load pockets can reduce grid congestion, potentially deferring or displacing transmission and distribution infrastructure investments. A 2013 study found that strategically sited DG yields improvements to grid system efficiency and provides additional reserve power, deferred costs, and other grid benefits (Crossborder Energy 2013). Widespread DG deployment can slow the growth-driven demand for more power lines and power stations.

States with Interconnection and Net Metering Standards

States typically regulate DG interconnections that do not involve power sales to third parties (i.e., interconnections that only send excess power back to the local utility). FERC regulates DG interconnections used to export power or for interstate commerce.[86] Because most DG is used to serve electric load at the customer's site, states approve the interconnection standards used for the majority of interconnections for smaller, clean DG systems.

Forty-five states (plus Washington D.C.) have adopted standard interconnection requirements for distributed generators as of March 2015 (see Figure 7.3.1). While these standards often cover a range of generating technologies, most include interconnection of renewable and CHP systems. In some cases, net metering provisions can be considered a subset of interconnection standards for small-scale projects. As of March 2015, 44 states (plus Washington D.C.) have rules or provisions for net metering (see Figure 7.3.2) (DSIRE 2015b). Currently, most states find that smaller DG systems are more likely to produce power primarily for their own use; exports to the grid tend to be incidental. The Solar Energy Industries Association estimates that solar DG

[85] For additional information on these policies, please see Chapter 5, "Renewable Portfolio Standards," and Section 7.4, "Customer Rates and Data Access."

[86] FERC does not have jurisdiction in Texas, Hawaii, or Alaska; http://www.ferc.gov/industries/electric.

systems export on average 20 to 40 percent of the total energy output of the system to the utility grid (SEIA 2014). Under net metering, when a DG system's output exceeds the site's electrical needs, the utility may credit the customer for excess power supplied to the grid. Some states require that the customer's credit surplus account be reset periodically, often on a monthly or annual basis. Additionally, states often cap the output of individual net metered systems or in aggregate at the grid level.

To encourage DG, many states have adopted simplified processes under net metering rules. Some of these state provisions are limited in scope—for example, applying only to relatively small systems,[87] specified technologies, or fuel types of special interest to policy-makers. More comprehensive net metering and interconnection policies provide detailed specifications and procedures for utilities and customers to follow, provide consistent rules for all utilities within the state,[88] and cover a complete range of system and fuel types, interconnection processes, and requirements.[89]

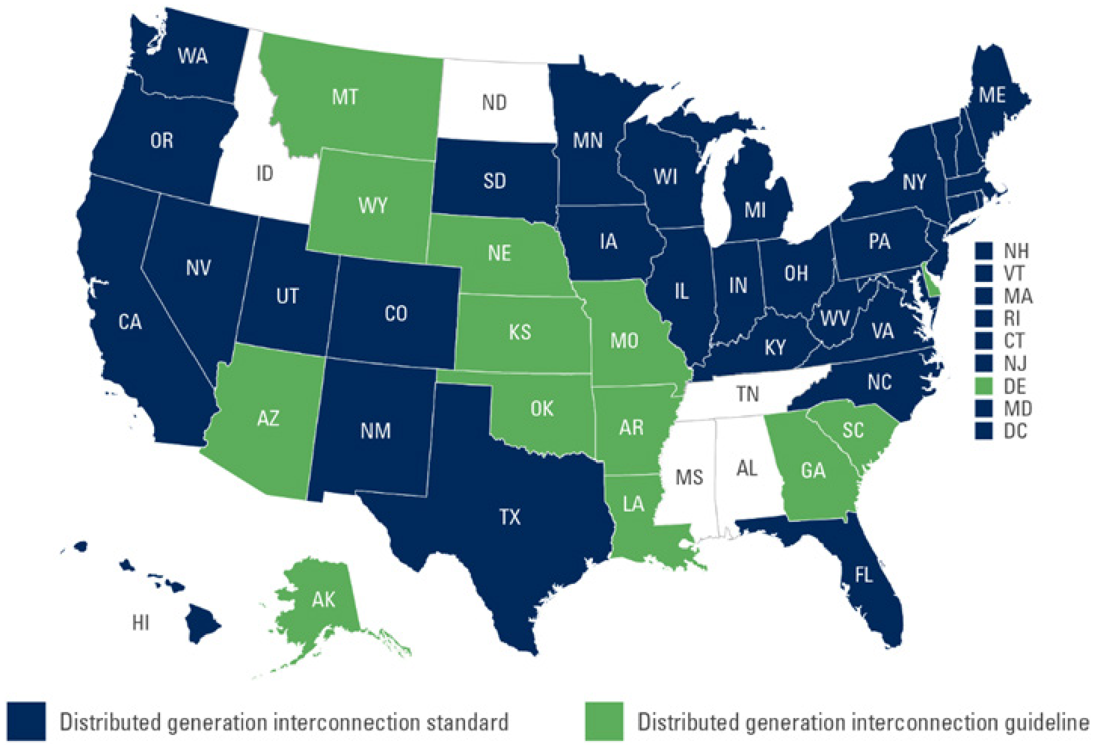
States consider a number of key factors when designing effective standard interconnection and net metering rules that balance the needs of DG owners, the utility company, and the public. This includes promoting broad participation during standards development, addressing a range of technology types and sizes, and considering current barriers to interconnection. In addition, it is important to consider state and federal policies that might influence the successful development and effective implementation of interconnection and net metering standards.

[87] Thirty-four of 39 states that have net metering rules limit system sizes to 100 kilowatts or less.

[88] States that have variable utility net metering policies that differ for investor-owned utilities, municipally owned utilities, cooperatively owned utilities, or alternative retail electric suppliers include Arizona, Florida, Idaho, and Illinois.

[89] Some states (e.g., New Hampshire and New Jersey) have developed standard interconnection processes and requirements as part of their net metering provision.

Figure 7.3.1: States with DG Interconnection Standards

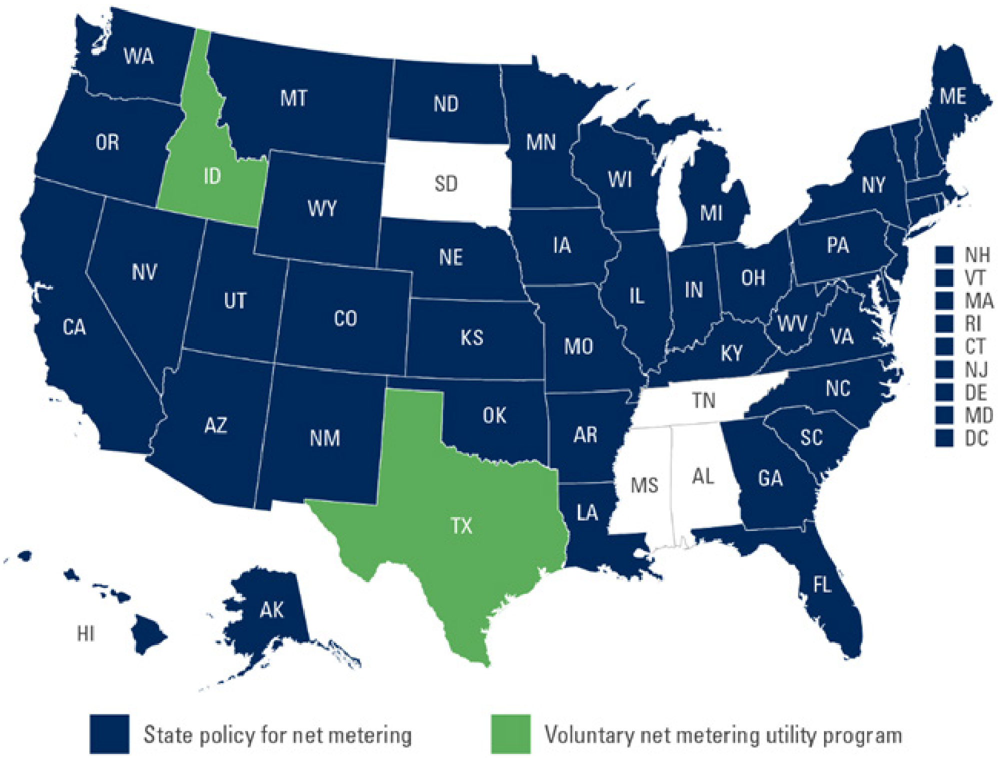


Maximum System Size for a State Interconnection Standard							
CA	None	KY*	30 kW	NJ	None	SD	10 MW
CO	10 MW	MA	None	NM	80 MW	TX	10 MW
CT	20 MW	MD	10 MW	NV	20 MW	UT	20 MW
DC	10 MW	ME	None	NY	2 MW	VA	20 MW
FL*	2 MW	MI	None	OH	20 MW	VT	None
HI	None	MN	10 MW	OR	10 MW	WA	20 MW
IA	10 MW	NC	None	PA*	5 MW	WI	15 MW
IL	None	NH*	1 MW	RI	None	WV	2 MW
IN	None						

* Denotes that policy only applies to net metered systems.
kW= kilowatts; MW= megawatts
Note: Certain states have different limits for residential and non-residential customers, while others have tiered limits.

Source: DSIRE 2015a

Figure 7.3.2: States with Net Metering Rules



Net Metering System Size Limit (kW)					
AK*	25	KY*	30	NV*	1,000
AR	25/300	LA	25/300	NY*	10/25/500/1,000/2,000
AZ	125% of demand	MA*	60/1,000/2,000/10,000	OH*	None
CA	1,000	MD	2,000	OK*	100
CO	120% of demand (for co-ops and munis: 10/25)	ME	660 (co-ops and munis, 100)	OR*	25/2,000
CT	2,000/3,000	MI*	150	PA*	50/3,000/5,000
DC	1,000/5,000/120% of demand	MN	40	RI*	5,000
DE	25/100/2,000 (co-ops and munis, 25/100/500)	MO	100	SC*	20/1,000
FL*	2,000	MT*	50	UT*	25/2,000
GA	10/100	NC*	1,000	VA*	20/500
HI	100	ND*	100	VT	20/250/2,250
IA*	500	NE	25	WA	100
IL*	40	NH	1,000	WI*	20
IN*	1,000	NJ*	None	WV	25/50/500/2,000
KS	15/100/150	NM*	80,000	WY*	25

* Denotes that policy only applies to certain types of utilities (e.g., investor-owned utilities).
Note: Certain states have different limits for residential and non-residential customers, while others have tiered limits.

Source: DSIRE 2015b

Designing Effective Interconnection and Net Metering Standards

Participants

Key stakeholders who can contribute to the process of developing effective interconnection and net metering standards include:

- *Electric utilities.* Utilities are responsible for maintaining the reliability and integrity of the grid and ensuring the safety of the public and their employees.
- *State PUCs.* PUCs have jurisdiction over investor-owned utilities (IOUs) and, in some cases, cooperatively and municipally owned utilities. They are often instrumental in setting policy to encourage onsite generation.
- *Developers and owners/operators of renewable energy and CHP systems as well as their respective trade organizations.* Developers and the customers that will rely on these systems can provide valuable technical information and real-world scenarios.
- *Technical allied organizations.* Organizations such as the Institute of Electric and Electronic Engineers (IEEE) and certifying organizations like the Underwriters Laboratories (UL) have been active in establishing interconnection protocols and equipment certification standards nationwide. In addition, organizations such as the Interstate Renewable Energy Council (IREC) help to develop national standards related to interconnection and net metering policy and to advance regulatory policy innovation.
- *Regional transmission organizations (RTOs).* These organizations may have already implemented interconnection standards using FERC requirements for large non-utility generators generally above 10 megawatts (MW).
- *Other government agencies.* Federal (e.g., FERC) and state environmental and public policy agencies—including state consumer advocates—can play an important role in establishing and developing interconnection and net metering standards.

Some states are bringing key stakeholders together to develop state-based standards via collaborative processes. For example, in Massachusetts, the DG Collaborative successfully brought together many diverse stakeholders to develop the interconnection rules now used by DG developers and customers in Massachusetts.

Emerging Approaches: Policy Variations to Net Metering

Some states have looked beyond standard net metering rules to employ innovative variations on these policies, which offer greater access to specific end consumer groups and end-use applications. For example, standard virtual net metering, meter aggregation, and community solar rules can allow customers to access self-generation and enjoy the benefits of net metering even if they are not able to directly host or invest in onsite generation. A common example of this is individually metered tenants within multi-unit housing buildings who, under newer meter aggregation rules, can share in the benefits of a centrally sited, onsite solar system across all tenant meters. In a few select cases, states and/or utilities have replaced standard net metering policies with new innovative approaches that seek to address utility concerns over cost recovery and ratepayer fairness issues. In 2013, the Minnesota State Legislature passed the first ever, statewide value-of-solar tariff, which many view as a more equitable and possibly more effective alternative to traditional net metering policies for onsite solar photovoltaic systems.[90]

[90] For more information on Solar Energy Legislation in Minnesota, see http://www.house.leg.state.mn.us/hrd/pubs/ss/sssolarleg.pdf.

Current Landscape of Interconnection for DG

Renewable energy and CHP systems used by commercial or industrial facilities are typically smaller than 10 MW in capacity. When designing and implementing standards for systems of this size, it is important to realize that the size of the system dictates how and by whom interconnection is regulated.

- *10 MW systems*. FERC has jurisdiction over developing standard interconnection rules for larger systems that are connected directly to the transmission grid. Historically, electric utilities owned most grid-connected generation systems. As a result of restructuring and other legislation (e.g., the Public Utility Regulatory Policy Act or PURPA), utilities were required to interconnect non-utility owned generators to the electric grid. States and regulatory agencies such as FERC have begun to develop or have already implemented standard interconnection rules for non-utility generators. However, these rules were historically applied to larger generating facilities (> 10 MW).
- *0.1 MW to 10 MW systems*. Systems in this size range still require regulatory attention in some states. This "intermediate" group represents systems that are interconnected to the distribution system but are larger than the systems typically covered by net metering rules and smaller than the large generating assets that interconnect directly to the transmission system and are regulated by FERC. In response to the mounting demands by customers and DG/CHP developers to interconnect generation systems to the grid, utilities have increasingly established some form of interconnection process and requirements. In addition, to increase utility confidence around DG systems, industry organizations such as the IEEE and UL have begun to develop standards that enable safe and reliable interconnection of generators to the grid. However, states need to establish standard interconnection rules for generation systems of all sizes.
- *< 100 kW (0.1 MW) systems*. Some states have developed provisions for the net metering of relatively small systems (i.e., < 100 kW). While these provisions are not typically as comprehensive as interconnection standards, they can provide a solid starting point for industry, customers, and utilities with respect to the connection of relatively small DG systems to the electric grid.

Typical Specifications

The specifications described below reflect typical elements found in existing state policies and compiled by other sources.[91] Effective interconnection standards often cover the following specifications:

Participants

- The breadth of customer classes covered under the policy. Effective state policies usually make all customer classes eligible.
- The breadth of state utilities covered under the policy. Effective state policies often cover investor, municipally, and cooperatively owned utilities.

Policy Design

- System size requirements. State policies do not typically establish individual system capacity limits and ensure that the policy applies to all state-jurisdictional interconnections.
- The type of technology that may be interconnected (e.g., inverter-based systems, induction generators, synchronous generators).
- The required components of the electric grid where the system will be interconnected (i.e., radial or network distribution, distribution or transmission level, maximum aggregate DG capacity on a circuit).

[91] Other sources include IREC's Model Net Metering Rules (2009) and Model Interconnection Rules (2013) (available at http://www.irecusa.org/publications/), ACEEE Interconnection Standards (ACEEE. 2013), and Freeing the Grid.org.

- Sensible limits on interconnection application fees. Effective policies keep application costs to a minimum, especially for smaller systems.
- Limitations on what utilities may require of systems, such as minimum metering requirements and an external disconnect switch for smaller, inverter-based systems. Effective policies would have the utility forgo requiring an external disconnect switch for smaller, inverter-based systems.
- Limitations on utility requirements of customers to purchase liability insurance (in addition to the coverage provided by a typical insurance policy) or to add the utility as an additional insured.

Process

- A standard agreement form that is easy to understand and free of burdensome terms.
- Sensible limits on procedural and administrative timelines for system interconnections. Effective policies ensure that these timelines are imposed and enforced.
- A review process. Best-in-class policies generally allow for different tiers with different levels of review to accommodate systems based on system capacity, complexity, and level of certification.
- Project technical screens to facilitate evaluation. Effective policies ensure that the technical criteria are both clear and transparent.
- A transparent and uniform dispute resolution process for affected stakeholders.

In addition, some states are developing different application processes and technical requirements for differently sized or certified systems. Since a DG system's size can range from a renewable system of only a few kilowatts (kW) to a CHP system of tens of MW, standards can be designed to accommodate this full range. Several states have developed a multi-tiered process for systems that range in size from less than 10 kW to more than 2 MW. Similar to the FERC guidelines, some states (Colorado, Florida, and North Carolina) have divided DG systems into three categories based on generator size. Other states use fewer (such as New York, Georgia, and West Virginia) or more (such as Delaware, Illinois, and Maine, where each have four) categories. States also define fees, insurance requirements, and processing times based on the category into which the DG falls. The level of technical review and interconnection requirements usually increases with generation capacity, although the requirements are ultimately driven by the applicant's impact on the grid as determined through the study process and the criteria identified in the application process.[92]

In states with a multi-tiered or screen interconnection process, smaller systems that meet IEEE and UL standards or certification generally pass through the interconnection process faster, pay less in fees, and require less protection equipment because there are fewer technical concerns. States that require faster application processing for smaller systems (< 10 to < 30 kW) include California, Connecticut, Massachusetts, Michigan, Minnesota, New York, Utah, and Wisconsin. For relatively large DG systems, processes and requirements may be similar or identical to those used for large central power generators. For mid-size systems, states may need to develop several levels of procedural and technical protocols to meet the range of needs for onsite generators, utilities, and regulators.

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[92] Thus, it is possible for a larger system to have a fairly expedited process if it is not deemed to have a notable or negative system impact. Utah's interconnection rules provide an example of this approach (see slide 5): http://www.naruc.org/international/Documents/Campbell%20Connection%20to%20Power%20Grids%20May%2023%209%20am.pdf.

States can promote DG with comprehensive net metering standards that employ strategies such as the following:

- Avoid placing an aggregate or statewide capacity limit on net metering.
- Ensure that any individual system size limitation is based only on the host customer's load or consumption (e.g., Arizona and Colorado).
- Allow the owner of a net metered system to retain ownership of RECs produced by the system, unless transferred to the utility or another party in exchange for acceptable compensation.
- Provide options for indefinite rollover, effectively or actually credited at retail rate, for net metered customers. Some states require that customers be paid for annual net excess generation at a price no lower than the average daytime wholesale price for the prior year.
- Avoid requiring retail electric customers to purchase new metering equipment. States can require utilities to make smart metering and other digital technology for energy management available to solar and other customers on a non-discriminatory and open-access basis. Integrating smart meters or other advanced metering technologies can lead to more detailed and reliable meter data, which in turn can lead to more efficient planning and energy use.
- Allow all customers to participate in net metering.
- Provide options for virtual net metering and meter aggregation.

Constraints

Designing new DG interconnection and net metering rules could resolve recurring barriers encountered by applicants for DG system interconnection. These barriers have been well-documented (NREL 2000; Schwartz 2005). Four areas in which a DG developer typically confronts problems include:

- *Costly technical system requirements.* Utilities often require additional measures related to the safety and operation of DG systems and their compatibility with the grid. For example, customers may be faced with costly electric service and grid upgrades as a condition of interconnection. Another frequently cited and particularly costly (e.g., $1,000 to $6,000) technical requirement for smaller DG systems (e.g., up to 200 kW) is the installation of an exterior manual disconnect switch that can be accessed by the utility to isolate the system from the grid, despite the fact that many grid tied systems have anti-islanding features that make such manual disconnects redundant. States may consider limiting the types of additional requirements that utilities can require of systems integrators beyond that which is covered in interconnection or net metering policies.
- *Utility business practices.* States can set policy direction for the contractual and procedural interconnection requirements that are imposed on system developers to be equitable and commensurate with the size and complexity of the system seeking interconnection. Limiting the length of the application review periods or technical study requirements can reduce what are often high costs for smaller DG systems to interconnect to the grid.
- *Regulatory constraints.* Such constraints can arise from tariff and rate conditions, including the prohibition of interconnection of generators that operate in parallel with the electric grid.[93] In some instances,

[93] When a CHP system is interconnected to the grid and operates in parallel with the grid, the utility only has to provide power above and beyond what the onsite CHP system can supply.

environmental permitting or emission limits can also create barriers. For more information on the barriers posed to DG systems by tariff and rate issues, see Chapter 6, "Policy Considerations for Combined Heat and Power," and Section 7.4, "Customer Rates and Data Access."

- *Local permitting constraints.* System permitting requirements are sometimes not well-defined and are often not uniform.

Some states are beginning to address these areas of concern through a combination of policy actions and regulatory changes to remove or alter requirements that they believe are inappropriate for the scale of small DG units.

Interaction with Federal Policies

States have found that several federal initiatives can be utilized when designing their own interconnection standards:

- In 2006, FERC set standard terms and conditions for public utilities to interconnect new DG sources with Small Generator Interconnection Procedures (SGIP) and the Small Generator Interconnection Agreement (SGIA). These requirements were developed based on requirements in FERC Orders 2006, 2006-A, and 2006-B. They apply to FERC-jurisdictional interconnections that interconnect at the transmission level. The FERC standards generally do not apply to distribution-level interconnection, which is regulated by state PUCs. The SGIP contain technical procedures as well as standard contractual provisions. They provide three ways to evaluate an interconnection request. The SGIP require interconnection equipment to be certified according to IEEE Standards 1547 and UL 1741. The SGIP address interconnection to spot networks for inverter-based DG. They do not address other interconnections to spot and area networks. The SGIP also do not cover any external disconnect switch requirements. The SGIA was developed for all interconnection requests submitted under the SGIP and governs the terms and conditions under which the Interconnection Customer's Small Generating Facility will interconnect with, and operate in parallel with, the Transmission Provider's Transmission System.
- In November 2013, FERC adopted several updates to the SGIP through Order 792. Among other changes, these updates added energy storage to the list of resources eligible to interconnect under FERC procedures. States may want to consider how state interconnection rules accommodate storage assets and how they interact with existing FERC orders.[94] While FERC's updates are not binding for states, they can provide useful models for establishing provisions that anticipate and enable higher DG penetration. Ohio is an example of a state that recently adopted substantial portions of the SGIP.[95]
- Under the Public Utility Regulatory Policy Act (PURPA), utilities are required to allow interconnection by qualifying facilities. States have significant flexibility in administering PURPA, although amendments made in 2005 and FERC decisions have limited the applicability of PURPA in some regions, particularly for facilities larger than 20 MW. In 2010, FERC ruled that California's "multi-tiered" avoided-cost-rate structure for a feed-in tariff for CHP systems of up to 20 MW is consistent with PURPA. FERC affirmed that state procurement obligations can be considered when calculating avoided cost; for example, requirements that utilities buy particular sources of energy with certain characteristics (e.g., renewable energy) to meet procurement obligations.

[94] For more information on FERC's SGIA and SGIP, see http://www.ferc.gov/whats-new/comm-meet/2013/112113/E-1.pdf.

[95] http://www.irecusa.org/2013/12/ohio-joins-top-states-improving-interconnection-procedures-for-renewables/

- Section 1254 of the Energy Policy Act of 2005 (DOE 2007) required each state regulatory authority to determine whether to require interconnection service for any utility consumer who had onsite generation by August 8, 2007. The Distributed Energy Interconnection Procedures were developed as an outcome of this requirement. In the Procedures, the U.S. Department of Energy's (DOE's) Offices of Energy Efficiency and Renewable Energy and of Electricity Delivery and Energy Reliability encourage state and non-state jurisdictional utilities to consider best practices in establishing interconnection procedures.

Interaction with State Policies

Interconnection and net metering standards are critical policies that complement other clean energy policies and programs such as state RPSs (see Chapter 5, "Renewable Portfolio Standards"), clean energy fund investments (see Chapter 3, "Funding and Financial Incentive Policies"), and utility planning practices (see Section 7.1, "Electricity Resource Planning and Procurement"). Such standards can also help states achieve other related environmental, energy, and economic goals. For example, by providing incentives to site renewable energy on formerly contaminated lands, landfills, or mine sites, the state can help protect open space and transform blighted properties into community assets.[96]

Best Practices: Designing a Net Metering Standard

- Ensure the customer's right to generate electricity and connect to the grid without discrimination or undue process.
- Ensure that the value of DG electricity is quantified fairly and that DG customers are adequately compensated.
- Avoid unfair and discriminatory cost recovery practices. If the utility implements charges to recover embedded net fixed costs, ensure that these charges are applied only after accounting for all utility benefits and offset cost reductions due to DG.
- Ensure that net metering rules, regulations, and practices are applied equally statewide.
- Ensure that the policy provides transparent access to data, such as load data (including hourly profiles), so customers can understand the economic implications of adopting onsite clean energy technologies.
- Avoid restrictive total program or state (aggregate) capacity limits.
- Avoid restrictive individual system capacity limits beyond that of the host customer's load or electricity consumption.
- Ensure that the net metering system owner retains renewable energy certificate (REC) ownership unless the REC is transferred to another party in exchange for fair compensation.
- Ensure that monthly or annual "rollover" provisions provide the net metering customer compensation at a retail rate for excess generation sent to the grid.
- Provide virtual net metering and meter aggregation options to ensure that all customers are able to participate in net metering.

[96] For example, Vermont's Act 99 of 2014 included specific considerations that can facilitate solar installations on landfill sites, while New Jersey's Solar Act of 2012 (S.B. 1925) authorized a new incentive to cover the additional costs for deploying solar electric power generation facilities on brownfield sites. For more examples and resources regarding renewable energy development on contaminated lands, see EPA's RE-Powering America's Land initiative at www.epa.gov/renewableenergyland/.

Best Practices: Designing an Interconnection Standard

The following are a compilation of best practices derived from current literature or from existing state policy examples.[97]

Participants

- Ensure that all customer classes are eligible under the policy.
- Ensure that interconnection policies apply equally to all utilities (including municipally and cooperatively owned utilities) statewide.

Policy Design

- Work collaboratively with interested parties to develop interconnection rules that are clear, concise, and applicable to all potential DG technologies. This will streamline the process and avoid untimely and costly rework.
- Develop standards that cover the scope of the desired DG technologies, generator types, sizes, and distribution system types.
- Minimize related application costs, particularly for smaller systems.
- Avoid restrictive individual system capacity limits.
- Avoid restrictive requirements for external disconnect switches for smaller, inverter-based systems.
- Avoid restrictive requirements that place unnecessary mandates on customers to buy liability insurance or require customers to make the utility an additional insured party.
- Consider adopting portions of national models (such as those developed by the National Association of Regulatory Utility Commissioners, IREC, and FERC) and successful programs in other states, or consider using these models as a template in developing a state-based standard. Also, consistency within a region increases the effectiveness of these standards.
- Try to maximize consistency between the RTO and the state standards for large generators.
- Develop consistency among states based on common practices to reduce compliance costs for the industry.

Process

- Ensure that a standard form interconnection agreement be available and easy to understand.
- Establish that reasonable, punctual procedural timelines should be adopted and enforced.
- Address all components of the interconnection process, including issues related to both the application process and technical requirements.
- Develop an application process that is streamlined with reasonable requirements and fees. Consider making the process and related fees commensurate with generator size. For example, develop a straightforward process for smaller or inverter-based systems and more detailed procedures for larger systems or those utilizing rotating devices (such as synchronous or induction motors) to fully assess their potential impact on the electrical system.
- Create a streamlined process for generators that are certified compliant with certain IEEE and UL standards. UL Standard 1741, "Inverters, Converters and Charge Controllers for Use in Independent Power Systems," provides design standards for inverter-based systems under 10 kW. IEEE Standard 1547, "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems," establishes design specifications and provides technical and test specifications for systems rated up to 10 MW. These standards can be used to certify electrical protection capability.
- Provide for a multi-tier (three to four separate levels) review process to accommodate systems based on system capacity, complexity, and level of certification.
- Identify and establish clear, transparent technical screens across all system tiers.
- Ensure that the interconnection rule includes a dispute resolution process for involved stakeholders.

[97] Best practice examples taken from the following sources: IREC, FreeingTheGrid.org, and ACEEE Interconnection Standards (ACEEE. 2013).

Implementation and Evaluation

This section describes the implementation and evaluation of new interconnection standards and net metering practices, including best practices that states have found successful.

Administering Body

While individual states may develop interconnection standards that are then approved by the PUC, utilities are ultimately responsible for their implementation.

Evaluation/Oversight

By establishing clearly defined categories of technologies and generation systems, utilities are able to streamline the process for customers and lessen the administrative time related to reviewing interconnection applications. For example, some states create multiple categories and tiers for reviewing applications with established maximum review periods. Across these technology categories, the maximum processing time allowed can vary by more than a factor of five depending on the technical complexity and size of the interconnection. Several states (including California, Connecticut, Massachusetts, Michigan, Minnesota, New York, and Wisconsin) have created tiered application processes based on system size and other factors. This tiered approach streamlines the process for smaller systems while maintaining a standard process for larger systems.

- A streamlined process that applies to smaller[98] or simpler systems (e.g., inverter-based) could have lower fees, shorter timelines, and fewer requirements for system impact studies. In some cases, states (i.e., California and New York) have pre-certified certain devices. Other states (i.e., Connecticut, Massachusetts, Minnesota, New Jersey, and Texas) require compliance with UL 1741 or IEEE 1547 and other applicable standards to expedite approval.
- Systems in a standard process are subject to a comprehensive evaluation. Applicants for these systems are typically required to pay additional fees for impact studies to determine how the DG may affect the performance and reliability of the electrical grid. Because of the higher degree of technical complexity, fees are higher and processing times are longer.

Best Practices: Implementing an Interconnection or Net Metering Standard

The best practices identified below will help guide states in implementing interconnection or net metering standards. These best practices are based on the experiences of states that have implemented such standards.

- Consider working as a collaborative to establish monitoring activities that evaluate the effectiveness of interconnection or net metering standards and application processes.
- Periodically review and update standards based on monitoring activities, including feedback from utilities and applicants.
- Keep abreast of changes in DG/CHP and electric utility technology and design enhancements, since these may affect existing standards, such as streamlining the application process and interconnection requirements.
- Consider working with groups such as IEEE to monitor industry activities and to stay up-to-date on standards developed and enacted by these organizations.

[98] California, Connecticut, Massachusetts, Michigan, Minnesota, New York, and Wisconsin require faster processing of smaller system (< 10 kW to < 30 kW) applications.

State Examples

There is tremendous diversity among the key elements of interconnection standards recently established at the state level. In the examples presented below, application processes such as fees, timelines, and eligibility criteria differ in each state.

Greater similarities are emerging among states' technical requirements, and this consistency is making it easier to increase the amount of clean DG in the states.

Massachusetts

Massachusetts' initial net metering rules were created in 1982 by the state's Department of Public Utilities (DPU). These rules have been modified several times and in August 2009, the DPU issued its model net metering tariff so that customers in Massachusetts are subject to the same net metering tariffs regardless of utility. The state's IOUs must offer net metering. Massachusetts' interconnection standards apply to all forms of DG, including renewables, and to all customers of the state's three IOUs (Unitil, Eversource, and National Grid). Both fossil-fueled and renewably fueled CHP systems are eligible for standardized interconnection. However, renewably fueled CHP systems alone are eligible for net metering.

Massachusetts' interconnection and net metering policies stand out on the following merits:

- The state's Model Interconnection Tariff provides for three system interconnection options: a simplified process, an expedited process, and a standard process. The size and technical complexity of each system determines the interconnection pathway.
- Massachusetts' rules allow for a manual external disconnect switch to be required at the discretion of the utility.
- Utilities are required to collect and track information related to the interconnection process in order to improve and update the standards.
- Massachusetts' interconnection policy was designed to pay special attention to network systems found in dense urban areas, which required a transparent review and screening process for projects.
- The state's net metering policy is open to a wide variety of renewable and other DG technologies.
- The net metering policies are applicable to all IOUs within the state.
- There are three different classifications of net metered systems based on the size of the applicant system.
- System owners are afforded the ownership of all related environmental benefits such as RECs.
- Massachusetts' Solar Renewable Energy Credit program includes specific incentives for renewable energy on landfills and brownfields.
- Massachusetts also allows "neighborhood net metering" for neighborhood-based Class I, II, or III facilities that are owned by (or serve the energy needs of) a group of 10 or more residential customers in a single neighborhood and served by a single utility.
- The net metering laws establish various system capacity limits, such as 10 MW for municipal or government entities, 2 MW for all other Class III systems, 1 MW for all other Class II systems, and 60 kW for all other Class I systems.

Websites:
http://programs.dsireusa.org/system/program/detail/986
http://programs.dsireusa.org/system/program/detail/986
http://www.epa.gov/chp/policies/policies/mamassachusettsnetmeteringrules.html

Oregon

Oregon has three separate interconnection standards: one for its net metered systems made up of primary investor-owned (PGE and PacifiCorp), municipally owned, and cooperatively owned utilities; one for small generator facilities (non-net metered systems); and one for large generator facilities (non-net metered systems). The Oregon rules do not apply to customers of Idaho Power, which provides net metering to Oregon customers pursuant to rules adopted by the Idaho PUC (DSIRE 2014a). Both fossil-fueled and renewably fueled net metered systems, including CHP systems, are eligible for standardized interconnection. Oregon is one of few states to receive an "A" grade for both its interconnection and net metering policies in FreeingTheGrid.org's survey of state policies.

Oregon's interconnection and net metering policies stand out for the following reasons:

- The rules differentiate between system size classes, allowing for small, non-net metered generator facilities up to 10 MW.
- Oregon also requires that utilities provide for the use of a standard interconnection application, a standard agreement, and reasonable procedural timelines.
- All utilities must establish a single point of contact through which applicants can obtain basic information regarding the interconnection process.
- Oregon does not require a manual, external disconnect switch for systems smaller than 25 kW.
- Utilities may not require customers to purchase additional insurance or to name the utility as an additional insured party on the applicant's liability policy.
- Net metered systems have three levels of interconnection review with reasonable application fees.
- Oregon maintains an individual system capacity limit of 25 kW to 2 MW for non-residential applications.
- The state allows for net excess generation to be carried over monthly as a kilowatt-hour (kWh) credit for a 12-month period.
- Municipally owned utilities, cooperatively owned utilities, and public utility districts are required to offer net metering up to 25 kW for non-residential systems and 10 kW for residential systems.
- In 2008, Oregon authorized third-party ownership for renewable energy installations of net metered systems.
- Customers own all associated RECs from net metered systems.

Websites:
http://programs.dsireusa.org/system/program/detail/802
http://programs.dsireusa.org/system/program/detail/39
http://epa.gov/chp/policies/policies/ororegoninterconnectionstandards.html

Utah

Utah requires the state's IOU, Rocky Mountain Power, and cooperatively owned utilities serving greater than 10,000 customers to offer net metering to customers who generate electricity. In 2010, FreeingTheGrid.org gave Utah's interconnection and net metering policies an "A" ranking based on a scoring system that compares state rules against a standard best practice model policy. In Utah, renewable fuels such as waste gas and waste heat capture and recovery are eligible under the state's interconnection standards. Only renewably fueled CHP systems are eligible under the state net metering and interconnection standards.

Utah's interconnection and net metering policies stand out for the following reasons:

- Utah's interconnection rules are based on FERC's interconnection standards for small generators, adopted in May 2005 by FERC Order 2006.
- The state's interconnection requirements, standards, and review procedures are divided into three levels for systems up to 20 MW in capacity, based on system complexity. Level 1 applies to inverter-based systems under 25 kW. Level 2 applies to systems between 25 kW and 2 MW that fail to qualify under Level 1. Level 3 applies to systems under 20 MW that do not qualify for Level 1 or 2 interconnections.
- Utah's net metering policies apply equally to the state's IOUs and rural cooperatively owned utilities.
- Utah has set system capacity limits at 2 MW for non-residential and 25 kW for residential net metered systems.
- For Rocky Mountain Power, both residential and small commercial customers may accrue excess kWh credits against their next bill at retail rate on a kWh-for-kWh basis. Any credits remaining at the end of a 12-month billing cycle are granted to the utility.
- For Rocky Mountain Power, large commercial and industrial customers with demand charges may choose between valuing net excess generation at an avoided-cost-based rate or at an alternative rate based on utility revenue and sales contained in FERC Form No. 1.
- System owners own the RECs associated with the system.
- Utah authorizes meter aggregation for customers who have multiple meters on or adjacent to the same site.

Websites:
http://programs.dsireusa.org/system/program/detail/806
http://programs.dsireusa.org/system/program/detail/743
http://www.epa.gov/chp/policies/policies/ututahnetmeteringrules.html
http://epa.gov/chp/policies/policies/ututahinterconnectionstandards.html

What States Can Do

States have adopted successful interconnection and net metering standards that expedite the implementation of clean energy technologies while accounting for the reliability and safety needs of the utility companies. Action steps for both initiating a program to establish interconnection and net metering rules and for ensuring the ongoing success of the rules after adoption are described below. Importantly, the success of effective interconnection standards is enhanced by effective net metering standards in place. States have recognized the need for concurrent net metering standards by either incorporating net metering requirements or by establishing separate net metering standards.

Action Steps for States

States That Have Existing Interconnection and Net Metering Standards

A priority after establishing standard interconnection and net metering rules is to identify and mitigate issues that might adversely affect the success of the rules. Being able to demonstrate the desired benefits is critical to their acceptance and use by stakeholders. The following strategies demonstrate these benefits:

- Many states can improve upon existing interconnection and net metering rules by comparing them to established model rules and best practices. IREC and FreeingTheGrid.org are sources for model rules.
- Monitor interconnection applications to determine if the standards ease the process for applicants and cover all types of interconnected systems. States can also monitor utility compliance with the new standards or create a complaint/dispute resolution point of contact.
- If resources permit, identify an appropriate organization to maintain a database on interconnection applications and new DG systems, evaluate the data, and convene key interconnection stakeholders when necessary.
- Modify and change interconnection or net metering rules as necessary to respond to the results of monitoring and evaluation activities.

States That Do Not Have Existing Interconnection and Net Metering Standards

Public support can help establish standard interconnection rules. The following strategies foster support from public officials and other stakeholders:

- Ascertain the level of demand and support for standard interconnection and net metering rules in the state from both public office holders and key industry members (e.g., utilities, equipment manufacturers, project developers, and potential system owners). If awareness is low, consider implementing an educational effort targeted at key stakeholders to raise awareness of the environmental and, especially, economic benefits resulting from uniform interconnection rules. For example, demonstrate that DG can result in enhanced reliability and reduced grid congestion. A 2013 study found that strategically sited DG yields improvements to grid system efficiency and provides additional reserve power, deferred costs, and other grid benefits (Crossborder Energy 2013). If resources are available, perform an analysis of these benefits and implement a pilot project (e.g., similar to Bonneville Power Authority's "non-wires" pilot program [BPA 2005] or the Massachusetts Technology Collaborative's Utility Congestion Relief Pilot Projects [RET 2005]) that promotes DG along with energy efficiency and voluntary transmission reduction. While this type of analysis is not essential, states have found it to be helpful.
- Establish a collaborative working group of key stakeholders to develop recommendations for a standard interconnection process and technical requirements. Open a docket at the PUC with the goal of receiving stakeholder comments and developing a draft regulation for consideration by the state PUC.
- If necessary, work with members of the legislature and the PUC to develop support for passage of the interconnection and net metering rules.
- Remember that implementing interconnection standards may take some years. States have found that success is driven by the inherent value of DG, which eventually becomes evident to stakeholders.
- Consider existing federal and state standards while developing new interconnection procedures and rely on accepted IEEE and UL standards to develop interconnection technical requirements.

Related Actions

- Interconnection standards are most effective in combination with tariffs and regulations that encourage DG. If current tariffs and regulations discourage DG—for example, through high standby charges or backup rates—then interconnection standards may not result in DG growth. Tariffs that encourage DG growth may allow customers to sell excess electricity back to the utility at or near retail rates.
- More generally, utilities can offer certain financial incentives to discourage customers from making their own electricity and discourage DG deployment. This is especially true when utilities' revenues are tied to the volume of electricity they sell, which is known as the throughput incentive. Some states have implemented policies that help decouple revenue from sales volumes, thus reducing disincentives for DG. For more information about these policies and about utility financial incentives in general, see Section 7.2, "Policies That Sustain Utility Financial Health."
- Communicate the results to state officials, public office holders, and the public.
- Include key stakeholders (e.g., utilities, equipment manufacturers, project developers, potential customers, advocacy groups, and regulators) in the development of the standard interconnection rules. Stakeholders can also contribute to rule modification based on the results of ongoing monitoring and evaluation.

Information Resources

State-by-State Assessment

Title/Description	URL Address
Database of State Incentives for Renewables and Efficiency (DSIRE). This database provides information on state interconnection policies. It also provides comparative information on policies for each state.	http://www.dsireusa.org
dCHPP (CHP Policies and Incentives Database). This online database allows users to search for CHP policies and incentives on interconnection by state or at the federal level.	http://www.epa.gov/chp/policies/database.html
Eastern Interconnection States Planning Council EZ Mapping Tool. This resource allows users to query state policies on a wide variety of topics.	https://eispctools.anl.gov/policy_query

Federal Resources

Title/Description	URL Address
Distributed Generation Interconnection Collaborative. DOE's National Renewable Energy Laboratory (NREL) actively participates in many of the programs that create national standards for interconnection.	http://www.nrel.gov/tech_deployment/dgic.html
The Combined Heat and Power Partnership (CHPP). EPA's CHPP is a voluntary program that seeks to reduce the environmental impact of energy generation by promoting the use of CHP. The CHPP helps states identify opportunities for policy development (energy, environmental, economic) to encourage energy efficiency through CHP and can provide additional assistance to help states implement standard interconnection.	http://www.epa.gov/chp/
RE-Powering America's Land: Mapping and Screening Tools. This EPA website provides tools for evaluating the renewable energy potential for current and formerly contaminated lands, landfills, and mine sites. This initiative identifies the renewable energy potential of these sites and provides other useful resources for communities, developers, industry, state and local governments, or anyone interested in reusing these sites for renewable energy development. In particular, see the Solar and Wind Site Screening Decision Trees.	http://www.epa.gov/renewableenergyland/rd_mapping_tool.htm
The Effect of State Policy Suites on the Development of Solar Markets. This NREL paper uses statistical analysis and case studies to examine the effectiveness of state policies in fostering successful solar photovoltaic markets.	www.nrel.gov/docs/fy15osti/62506.pdf

National Standards Organizations

Title/Description	URL Address
IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems. The IEEE Standards Association has developed standards relevant to many of the technical aspects of interconnection. In particular, Standard 1547 provides requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection.	http://grouper.ieee.org/groups/scc21/1547/1547_index.html
UL 1741: Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources. UL also develops standards for interconnecting DG. In particular, UL 1741 will combine product safety requirements with the utility interconnection requirements developed in the IEEE 1547 standard to provide a testing standard to evaluate and certify DG products.	http://ulstandards.ul.com/standard/?id=1741

Examples of Standard Interconnection Rules

Title/Description	URL Address
IREC Regulatory Reform. IREC has prepared a model interconnection rule and a guide to connecting DG to the grid.	http://www.irecusa.org/regulatory-reform/
Model Interconnection Procedures and Model Net Metering Program Rules. These documents provide state policy-makers with a clear baseline to measure the minimum adequacy of their interconnection procedures, along with guidance to improve those procedures.	http://www.irecusa.org/regulatory-reform/interconnection/ (interconnection) http://www.irecusa.org/regulatory-reform/net-metering/ (net metering)
Connecting to the Grid: A Guide to Distributed Generation Interconnection Issues. This guide provides a model for stakeholders to develop state-level interconnection standards.	http://www.solarelectricpower.org/media/8165/irecconnecting-to-the-grid09.pdf
Freeing the Grid. This website and annual report, co-produced by IREC and Vote Solar, provides information on the status of state interconnection and net metering policies. Also available on this site are best and worst practice approaches to policy development as well as model rules.	http://freeingthegrid.org/
Model Interconnection Tariff. Massachusetts adopted this model interconnection tariff to establish a clear, transparent, and standard process for DG interconnection applications.	https://sites.google.com/site/massdgic/home
Mid-Atlantic Distributed Resources Initiative (MADRI) Working Group. In a collaborative process, MADRI has developed a sample interconnection standard.	http://www.energetics.com/MADRI/
Model Distributed Generation Interconnection Procedures and Agreement. NARUC developed these documents for small DG resources.	http://www.naruc.org/grants/Documents/dgiaip.pdf
Chapter 3. Interconnection Standards for CHP with No Electricity Export. This *Guide to the Successful Implementation of State Combined Heat and Power Policies* informs state utility regulators and other state policymakers with actionable information to assist them in implementing key state policies that impact CHP. It discusses five policy categories, including interconnection, and highlights successful state CHP implementation approaches within each category.	https://www4.eere.energy.gov/seeaction/system/files/documents/publications/chapters/see_action_chp_policies_guide_chap_3.pdf

Other Resources

Title/Description	URL Address
Removing Regulatory Barriers to Distributed Generation. This report by the Oregon PUC addresses barriers for DG.	http://www.puc.state.or.us/meetings/pmemos/2005/030805/reg3.pdf
Making Connections: Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects. This NREL report studies the barriers projects have faced interconnecting to the grid.	http://www.nrel.gov/docs/fy00osti/28053.pdf
Optimal Portfolio Methodology for Assessing Distributed Energy Resources Benefits for the Energynet: CEC, PIER Energy-Related Environmental Research (CEC-500-2005-061-D). This project addresses whether DG, demand response, and localized reactive power sources, or distributed energy resources, can be shown to enhance the performance of an electric power transmission and distribution system.	http://www.energy.ca.gov/2005publications/CEC-500-2005-096/CEC-500-2005-096.PDF
Model Regulations for the Output of Specified Air Emissions from Smaller-Scale Electric Generation Resources. The Regulatory Assistance Project (RAP) prepared a Distributed Resource Policy Series to support state policy efforts, and facilitated the creation of a Model Distributed Generation Emissions Rule for use in air permitting of DG.	http://www.raponline.org/document/download/id/174
Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition. This RAP paper outlines current tariffs and considerations for regulators as they weigh the benefits, costs, and net value to DG adopters, non-adopters, the utility system, and society as a whole.	http://www.raponline.org/document/download/id/6898
Rate Design Pathways to Fair Utility Rates for Solar PV in a Distributed Energy Age. This article from ElectricityPolicy.com provides insights on how states can accommodate growth in the solar photovoltaic market.	http://www.electricitypolicy.com/articles/7530-rate-design-pathways-to-fair-utility-rates-for-solar-pv-in-a-distributed-energy-age
The CHP Association (CHPA). CHPA brings together diverse market interests to promote the growth of clean, efficient CHP in the United States. As a result, they have been stakeholders in states that have developed standard interconnection rules.	http://chpassociation.org/

State Resources

State	Title/Description	URL Address
California	California Interconnection Guidebook: A Guide to Interconnecting Customer-owned Electric Generation Equipment to the Electric Utility Distribution System Using California's Electric Rule 21. This guidebook, written for the California Energy Commission's Public Interest Research Program in 2003, is intended to help customers interconnect electric generators to their investor-owned electric utility Distribution System under the California Public Utilities Commission's approved utility interconnection Rule 21.	http://www.energy.ca.gov/reports/2003-11-13_500-03-083F.PDF
	Decision Adopting Settlement Agreement Revising Distribution Level Interconnection Rules and Regulations (Decision 12-09-018). This 2012 order by the California Public Utilities Commission reformed Electric Tariff Rule 21, which governs the interconnection by electric generating facilities to the distribution systems of California IOUs.	http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M028/K168/28168335.pdf
Connecticut	DPUC Investigation into the Need for Interconnection Standards for Distributed Generation—Area Network Interconnection Standards. This decision provides revised guidelines for the Connecticut Department of Public Utility Control's joint interconnection guidelines to bring them into alignment with FERC Order 2006.	http://www.dpuc.state.ct.us/dockhist.nsf/8e6fc37a54110e3e852576190052b64d/0802f9f14f6a0ab18525775100510969?OpenDocument
	DPUC Investigation into the Need for Interconnection Standards for Distributed Generation–2007 Revisions. This docket provides status updates on the research and development of standards for interconnection from Connecticut's investor owned utilities.	http://www.dpuc.state.ct.us/dockhist.nsf/8e6fc37a54110e3e852576190052b64d/55810423d6501987852573e800837054?OpenDocument
Delaware	Interconnection Standards for Delmarva Power & Light Company's Delaware Operating Territory. This 2011 filing contains Delmarva Power & Light Company's interconnection standard for its Delaware operating territory in compliance with the Delaware PUC's Regulation Docket No. 49 and Order Numbers 7832 and 7984.	http://www.dsireusa.org/documents/Incentives/DE05R.pdf
	In the Matter of the Adoption of Rules and Regulations to Implement the Provisions of 26 DEL. C. CH. 10 Relating to the Creation of a Competitive Market for Retail Electric Supply Service (Order No. 7984).This 2011 proceeding revises Delaware net metering rules to include single customers with multiple accounts and multiple customers and multiple accounts served by community energy generation facilities.	http://depsc.delaware.gov/orders/7984.pdf

State	Title/Description	URL Address
Hawaii	Instituting a Proceeding to Investigate the Implementation of Reliability Standards for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited (Docket No. 2011-0206). This proceeding initiated an investigation to examine the implementation of reliability standards for utilities in the state of Hawaii, including interconnection of DG facilities.	http://dms.puc.hawaii.gov/dms/DocketSearch.jsp (Enter 2011-0206 in search box Docket No.)
	Decision and Order for Approval to Modify Rule 14H, Interconnection of Distributed Generating Facilities Operating in Parallel with the Companies Electrical Systems as Shown in Appendices I, II, and III (Docket No. 2010-0015). This 2011 decision updates Hawaii Electric Companies' Tariff Rule 14H, which governs the interconnection of distributed generating facilities, to facilitate the higher penetration of renewable distributed generating facilities.	http://www.dsireusa.org/documents/Incentives/HI01Rd.pdf
Massachusetts	Distributed Generation and Interconnection in Massachusetts. Massachusetts Department of Energy Resources Web page. This website provides resources and information on interconnection, net metering, and grid modernization in the state of Massachusetts.	https://sites.google.com/site/massdgic/
	Department Investigation on Distributed Generation Interconnection (Docket 11-75). This docket features an order approving an interconnection timeline enforcement mechanism, which requires the state's IOUs to file interconnection tariffs. The docket is also an ongoing investigation on DG interconnection.	http://web1.env.state.ma.us/DPU/FileRoom (Click Dockets/Filings and enter Docket #11-75 in search box to access materials)
	Inquiry into Net Metering and Interconnection of Distributed Generation (Docket 11-11). This 2011 docket establishes an inquiry into net metering and interconnection of DG.	http://web1.env.state.ma.us/DPU/FileRoom (Click Dockets/Filings and enter Docket #11-11 in search box to access materials)
Michigan	Customer Generation. Michigan Public Service Commission (PSC) Department of Licensing and Regulatory Affairs Web page. This page provides applications for interconnection and net metering, as well as generator interconnection procedures and parallel operating agreements.	http://www.michigan.gov/mpsc/0,1607,7-159-16393_48212---,00.html
	In the Matter, on the Commission's Own Motion, to Approve Procedure, Agreements, and Forms, for Use with the Category 1 and Category 2 Interconnection and Net Metering Programs (Docket No. U-15919). This 2012 case approves general interconnection procedures in the state of Michigan for projects up to 150 kW. Procedures are divided into two categories based on the aggregate generator size.	http://www.dleg.state.mi.us/mpsc/orders/electric/2012/u-15919_09-25-2012.pdf

State	Title/Description	URL Address
Minnesota	Distributed Generation. Minnesota Department of Commerce's Web page. This website contains general information on DG in Minnesota, including resources from stakeholder workshops held in 2011–2014 on issues related to DG resources.	http://mn.gov/commerce/energy/businesses/clean-energy/distributed-generation/index.jsp
	In the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities under Minnesota Laws 2001, Chapter 212. This 2004 order establishes guidelines for DG tariffs in Minnesota, and mandates that retail electric public utilities submit distribution tariffs consistent with the guidelines.	http://mn.gov/puc/portal/groups/public/documents/puc_pdf_orders/008982.pdf
New Hampshire	Net Metering for Customer-Owned Renewable Energy Generation Resources of 1,000 Kilowatts or Less. This code, enacted in 2001 and subsequently amended, establishes interconnection requirements for net energy metering.	http://www.puc.state.nh.us/Regulatory/Rules/PUC900.pdf
New Jersey	Net Metering and Interconnection. New Jersey Board of Public Utilities' Web page. This page explains net metering and interconnection requirements in the state of New Jersey.	http://www.njcleanenergy.com/renewable-energy/programs/net-metering-and-interconnection
	Interconnection of Class I Renewable Energy Systems N.J.A.C 14:8-5.1 et seq.). This administrative code, enacted in 2004, and subsequently amended, provides general interconnection provisions and lays out requirements for interconnection in the state of New Jersey.	http://www.lexisnexis.com/hottopics/njcode/ (Enter 14:8-5.1 into search box)
New York	Distributed Generation Information. New York PSC Web page. This page provides updated New York State standardized interconnection requirements.	http://www3.dps.ny.gov/W/PSCWeb.nsf/All/DCF68EFCA391AD6085257687006F396B?OpenDocument
	New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators 2 MW or Less Connected in Parallel with Utility Distribution Systems. This document, updated in 2014, contains standardized interconnection requirements for DG in New York state.	http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/dcf68efca391ad6085257687006f396b/$FILE/ATTP59JI.pdf/Final%20SIR%202-1-14.pdf
Ohio	Interconnection Forms and Interconnection Applicant Checklist. The Public Utilities Commission of Ohio Web page. This page provides sample interconnection forms, including applications and interconnection agreements, for the state of Ohio.	http://www.puco.ohio.gov/puco/index.cfm/puco-forms/interconnection-forms/#sthash.Tfd4dojZ.dpbs
	In the Matter of the Commissions Review of Chapter 4901:1-22 Ohio Administrative Code Regarding Interconnection Services (12-0251-EL-ORD).This case, opened in 2012, is an ongoing review of the administrative code regarding interconnection services in the state of Ohio.	http://dis.puc.state.oh.us/CaseRecord.aspx?CaseNo=12-2051

State	Title/Description	URL Address
Oregon	Net Metering Rules (R. 860-039).This 2007 document presents rules for net metering in the state of Oregon.	http://arcweb.sos.state.or.us/pages/rules/oars_800/oar_860/860_039.html
	Small Generator Interconnection Rules (R. 860-082). This 2009 document presents rules for interconnection in the state of Oregon.	http://arcweb.sos.state.or.us/pages/rules/oars_800/oar_860/860_082.html
Texas	Certification and Licensing. PUC of Texas Web page. This page contains forms, documents, and legislation for DG in the state of Texas, including technical requirements for interconnection.	http://www.puc.texas.gov/industry/electric/business/dg/Dg.aspx
	Distributed Generation Interconnection Manual. This manual, developed by the PUC of Texas in 2002, provides a guide for the inclusion of DG into the Texas electric system.	http://www.puc.texas.gov/industry/electric/business/dg/dgmanual.pdf
	Substantive Rule § 25.211—Interconnection of On-Site Distributed Generation (DG).This rule by the PUC of Texas in 1999 states the terms and conditions governing the interconnection and parallel of onsite DG in Texas.	http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.211/25.211ei.aspx
	Substantive Rule § 25.212—Technical Requirements for Interconnection and Parallel Operation of On-Site Distributed Generation. This rule by the PUC of Texas in 1999 states the technical requirements for interconnection and parallel operation of onsite DG in Texas.	http://www.puc.texas.gov/agency/rulesnlaws/subrules/electric/25.212/25.212ei.aspx
Utah	Net Metering of Electricity (Utah Code § 54-15-101 et seq.). This code, enacted in 2002, outlines rules for the net metering of electricity in the state of Utah.	http://le.utah.gov/UtahCode/section.jsp?code=54-15
	Electrical Interconnection (Utah Admin Code R746-312). This code, enacted in 2010, outlines rules for the interconnection of DG facilities in the state of Utah.	http://www.rules.utah.gov/publicat/code/r746/r746-312.htm
Wisconsin	Distributed Generation Interconnection Procedure. PSC of Wisconsin Web page. This page provides materials for DG interconnection procedures in the state of Wisconsin, including guidelines, points of contact for electric providers, and forms.	http://psc.wi.gov/utilityinfo/electric/distributedGeneration/interconnectionProcedure.htm
	Chapter PSC 119: Rules for Interconnecting Distributed Generation Facilities. This 2004 text provides rules for interconnecting DG facilities in the state of Wisconsin.	http://www.legis.state.wi.us/rsb/code/psc/psc119.pdf

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Title/Description	URL Address
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Crossborder Energy. 2013. Evaluating the Benefits and Costs of Net Energy Metering in California. Prepared for the Vote Solar Initiative. Crossborder Energy Comprehensive Consulting for the North American Energy Industry.	http://votesolar.org/wp-content/uploads/2013/01/Crossborder-Energy-CA-Net-Metering-Cost-Benefit-Jan-2013-final.pdf
DOE. 2007. Distributed Energy Interconnection Procedures Best Practices for Consideration. Office of Energy Efficiency and Renewable Energy and Office of Electricity Delivery and Energy Reliability. U.S. Department of Energy.	http://www1.eere.energy.gov/solar/pdfs/doe_interconnection_best_practices.pdf
DSIRE. 2013. Utah: Interconnection Standards. Database of State Incentives for Renewables and Efficiency.	http://programs.dsireusa.org/system/program/detail/806
DSIRE. 2014a. Massachusetts: Interconnection Standards. Database of State Incentives for Renewables and Efficiency.	http://programs.dsireusa.org/system/program/detail/986
DSIRE. 2014b. Massachusetts: Net Metering. Database of State Incentives for Renewables and Efficiency.	http://programs.dsireusa.org/system/program/detail/281
DSIRE. 2014c. Oregon: Interconnection Standards. Database of State Incentives for Renewables and Efficiency.	http://programs.dsireusa.org/system/program/detail/802
DSIRE. 2014d. Oregon: Net Metering. Database of State Incentives for Renewables and Efficiency.	http://programs.dsireusa.org/system/program/detail/39
DSIRE. 2014e. Utah: Net Metering. Database of State Incentives for Renewables and Efficiency.	http://programs.dsireusa.org/system/program/detail/743
DSIRE. 2015a. Summary Tables: Interconnection Policies. Database of State Incentives for Renewables and Efficiency. Accessed March 2015.	http://programs.dsireusa.org/system/program?type=14&category=2&
DSIRE. 2015b. Summary Tables: Net Metering. Database of State Incentives for Renewables and Efficiency. Accessed March 2015.	http://programs.dsireusa.org/system/program?type=37&category=2&
SEIA. 2014. Issues and Policies: Net Metering. Solar Energy Industries Association.	http://www.seia.org/policy/distributed-solar/net-metering

7.4 Customer Rates and Data Access

Policy Description and Objectives

Summary

Customers benefit economically from utility bill savings or direct payments for their electricity output when they improve their energy efficiency or install distributed renewable energy and combined heat and power (CHP). Consequently, the specifics of a customer's rates and other utility charges can drive the economic attractiveness of energy efficiency, distributed renewable energy, CHP, and other technologies, such as storage and electric vehicles. States have found that access to utility data on energy usage is key to helping customers understand and manage their utility bills and consider potential energy efficiency and clean energy investments.

Objective

The policies described in this section involve setting rates and giving customers access to information that will encourage them to use energy more efficiently or invest in distributed renewable energy and CHP. States have found that rate design and data access policies can help encourage additional customer investment in these technologies and practices while complementing the energy efficiency, renewable energy, and CHP policies discussed elsewhere in the *Guide to Action*, such as energy efficiency resource standard and renewable portfolio standard (RPS) policies.

In most cases, utility rates are not designed with energy efficiency and clean energy technology in mind. Utility rates are the outcome of a complex process that must take into account multiple objectives. There are usually three main priorities: 1) meeting utility revenue requirements, 2) fair apportionment of costs among customers, and 3) economic efficiency (Bonbright 1961; Phillips 1993). Other regulatory and legislative goals may include providing stable revenues for the utility and stable rates for customers, simplifying understanding and ease of implementation, encouraging effective load management, promoting social equity in the form of lifeline rates for people with low incomes, and promoting environmental sustainability in the form of rates that encourage reduced energy use and lower emissions.

Because states consider multiple priorities when designing rates, rate design may be more or less compatible with the adoption of energy efficiency, distributed renewable energy, and CHP. This section describes common rate forms and how they can affect the benefits and risks of these technologies and practices. This section also discusses the role of electronic energy use data (and related privacy protections). Electronic access to energy use data can help customers manage their utility bills and make informed decisions about participating in energy efficiency programs and investing in distributed renewables.

Types of Utility Rates

Table 7.4.1 summarizes nine types of rate designs and highlights whether each design focuses on a customer's net usage or focuses on generator output. Each type of rate design is described in more detail below, followed by a discussion about providing customers with access to detailed energy use data.

Table 7.4.1: Summary of Rate Designs

Rate Form	Effect or Goal of Design	Applies to Customer Usage or Generator Output
Energy Consumption Rates		
Flat Rates	Simplest rate form, often consisting of monthly demand/access charges and energy charges per kilowatt-hour consumed. Historically used to meet state policy objectives for rate design.	Customer usage
Inclining Block Rates	Promotes reduced monthly energy usage. Also provides bill reductions for consumers with smaller overall usage.	Customer usage
Time-Varying Rates (Time-of-Use and Real Time Pricing)	Promotes economically efficient consumer decisions by providing prices to customers that reflect the time-varying cost of energy.	Customer usage
Demand Charges	Incentivizes customers to reduce their demand during peak periods when electricity is more expensive for the utility to provide.	Customer usage
Technology Targeted Rates		
Standby Rates	Compensates the utility for having equipment ready and available to serve a customer when needed to provide backup for the customer's generator.	Generator output
Exit Fees	Allows the utility to charge customers for costs previously incurred by the utility even if the customer no longer requires grid service. Adds a disincentive for customers to depart from the grid.	Generator output
Net Energy Metering	Compensates customers for their generation output at rates that are equivalent to their retail rates.	Customer usage
Buyback Rates (Feed-in Tariffs)	Separates the value of customer-installed generation from the customer's rates. Compensates the customer for generation output.	Generator output
Electric Vehicle Rates	Provides time-of-use rates that incentivize off-peak charging.	Customer usage

Energy Consumption Rates

The first four types of rates relate to the way utilities charge customers for the amount of energy they use. While typically designed to meet the general ratemaking objectives described above, these rates can also incentivize energy efficiency and clean energy in a variety of ways.

Flat rates. The flat rate charges customers based on the total kilowatt-hours (kWh) of electricity or therms of natural gas they consume. In addition to these charges per unit of energy consumed, bills may also include a daily or monthly customer access charge to help cover the utility's fixed costs.[99] Flat rates are typically limited to residential and small commercial customers. Customers could realize cost savings if they adopt energy efficiency, distributed renewable energy, or CHP, but flat rates do not necessarily incentivize the customer to

[99] Access charges include items such as monthly customer charges or daily facility access fees. These charges and fees provide a stable revenue source for utilities that reduces the remaining costs that utilities must recover from customers via energy charges. For example, an all-energy rate might be 20 cents per kWh; whereas the addition of a $10 per month customer charge might allow a lower 18 cent per kWh rate.

adopt these technologies and practices in a manner that maximizes cost savings and environmental benefits across the electricity system as a whole.

***Inclining block rates*.** Under this rate form, the price per unit of electricity or natural gas increases with higher usage. Inclining block rates offer the advantages of being simple to understand and simple to meter and bill. Inclining block rates can also meet the policy goal of protecting small energy users. It was this desire to protect small users that prompted the adoption of inclining block rates in California. For larger users, inclining block rates offer a stronger price signal for energy efficiency and clean energy than a simple flat rate. In contrast, some utilities offer a declining block rate structure for their largest customers, in which the first block of usage is billed at a higher rate than subsequent usage.

Time-varying rates. Time-of-use (TOU) and real time pricing (RTP) rates refine the utility's pricing so that the cost of energy differs by season, month, time of day, or hour. Generally, natural gas rates will only vary by season or month, while electricity TOU prices will typically vary by season and consist of up to four pricing periods within each season that vary by time of day. RTP prices typically vary hourly. Other variations involve energy prices that are fixed for most of the year, but the utility can raise prices for a limited number of hours, or offer large credits for energy reductions in response to system needs or high market prices. Such hourly responses have existed for decades, but have historically been limited to large commercial and industrial customers. More recently, the implementation of advanced metering infrastructure (AMI) projects by utilities has enabled small commercial and residential customers to participate in RTP.[100]

TOU and RTP rates allow utilities to offer prices to customers that can better match the utility's supply costs. By reducing demand at peak times, these rates can decrease the need for utilities to build additional generation capacity or operate less efficient backup units. TOU and RTP prices can also provide larger economic incentives than flat rates for energy efficiency, distributed renewables, and CHP that provide relatively higher output during times of higher utility costs and prices—for example, solar power during hot, sunny summer days. Access to energy usage data and pricing information is important for customers who are on time-varying rates.

***Demand charges*.** With demand charges, customers pay for their energy usage and then pay an additional charge based on their peak demand during a particular period (a month, the year as a whole, or at a specific time of day). Demand charges reflect the fact that portions of the electricity system are sized to accommodate customers' peak loads. Demand charges have historically been limited to industrial and larger commercial customers because of the cost of advanced metering, but the spread of AMI to smaller customers presents additional opportunities—although the complexity of understanding and managing demand by smaller, less sophisticated customers remains an issue. (For more discussion about AMI and other modern grid technologies, see Section 7.5, "Maximizing Grid Investments to Achieve Energy Efficiency and Improve Renewable Energy Integration.")

Like TOU and RTP structures, demand charges can lead to environmental benefits and overall cost savings by decreasing the need for utilities to build additional generation capacity or operate less efficient backup units during periods of peak usage. To the extent that energy efficiency, distributed renewable energy, and CHP can

[100] For example, PG&E, Portland General Electric, and Georgia Power are offering real-time pricing to customers. For more information, see http://www.pge.com/en/mybusiness/rates/tvp/peakdaypricing.page, https://www.portlandgeneral.com/our_company/corporate_info/regulatory_documents/pdfs/schedules/Sched_012.pdf, and http://www.georgiapower.com/pricing/files/rates-and-schedules/CPP-R-1.pdf.

reduce peak demand, they can greatly reduce customer demand charges. Some customers have also installed electricity storage to reduce their demand charges.[101]

Technology-Targeted Rates

In some cases, customers who install technologies could be subject to rates that are specific to their installation of distributed renewable energy, CHP (see Chapter 6, "Policy Considerations for Combined Heat and Power"), storage equipment (see Section 7.5), or a unique energy-intensive end-use (e.g., electric vehicles). This section discusses several common types of technology-targeted rates.

Standby rates. Facilities that use distributed renewable energy or CHP may still need backup power from the grid when the onsite system is unavailable due to equipment failure, maintenance periods, or other planned outages. Electric utilities often assess standby charges to cover the additional costs they incur as they continue to provide adequate generation, transmission, or distribution capacity (depending on the structure of the utility) to meet these customers' needs. The utility's concern is that the customer could require power at a time when electricity is scarce or at a premium cost, and the utility must be prepared to serve load during such extreme conditions, sometimes on short notice (see the introduction to Chapter 7, "Electric Utility Policies," for additional discussion on how the electric power grid must match supply with demand).

The probability that any one generator will require standby service at the exact peak demand period is low, and the probability that all interconnected small-scale distributed renewable energy or CHP will need it at the same time is even lower. Consequently, states are exploring standby rate alternatives that may more accurately reflect these conditions (DOE 2012a; NRRI 2012). States are also looking for ways to account for the diversity of customer types[102] when determining the probability that the demand for standby service will coincide with peak (high-cost) hours.

Exit fees. When facilities reduce or end their use of electricity from the grid, this affects the utility's ability to recover fixed operating costs for the investments it has made to serve all ratepayers. These fixed costs are usually recovered over time and are often tied to kWh consumption. The remaining customers may eventually bear these costs. This can be particularly problematic if a large customer leaves a small electric system. To minimize potential rate increases due to the load loss,[103] utilities sometimes assess exit fees on departing loads.

As many states began to restructure (i.e., deregulate) their electricity markets during the 1990s, utilities that previously generated power began to focus on delivery only, which meant that more of their costs tended to be fixed (e.g., investments in transmission and distribution infrastructure). Thus, exit fees gained favor as a means to allow these utilities to recover historical or "stranded" costs. Some states, however, exempted certain generation projects from exit fees because of the other benefits they provided, such as grid congestion relief and reliability enhancement. For example, Massachusetts and Illinois exempted some or all CHP projects from their stranded cost recovery fees.

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101 See Section 7.5, "Maximizing Grid Investments to Achieve Energy Efficiency and Improve Renewable Energy Integration," for more information on electricity storage.

102 For example, some industrial facilities run three shifts per day while others only run one shift per day. This would lead to a three-fold disparity between peak and minimum power demand in two otherwise identical facilities.

103 Many factors affect utility rates and net revenues (e.g., customer growth, climate, fuel prices, and overall economic conditions). Therefore, a load reduction will not necessarily result in a net loss that would need to be recovered from the departing customer or other customers.

Net energy metering. Net metering is designed for customers who own small distributed generation (DG) systems. The basic principle behind net metering is that the amount of electricity produced by the DG system is measured against the amount of electricity used by the customer (i.e., the customer's load). If the DG system produces more electricity in any given month than the customer needs to meet its own load, the surplus electricity is exported to the grid for other customers to use. The customer then receives a bill credit for the surplus kWh, which can be used to offset electricity use in future months when the customer's load exceeds the DG system's production. This crediting system means that the utility is effectively purchasing the surplus electricity generated by the DG system at the full retail rate. Net metering programs typically address interconnection in a simple way, which is appropriate for small renewable projects. (For more information on net metering, see Section 7.3, "Interconnection and Net Metering Standards.")

Several aspects of net metering vary by state, including roll-over of bill credits and the maximum size of a net metered system. Net metering is designed for customers who install a small DG system that will produce roughly the same amount as the customer's load, not for utility-scale power producers whose systems export large amounts of electricity to the grid and support many customers' loads. Most states also set a limit on the aggregate capacity of net metered systems in each utility's territory. See Section 7.3 for a map of state net metering policies.

Buyback rates. The payment received for surplus power generated by distributed renewable energy and CHP projects can be a critical component of project economics. The price at which the utility is willing to purchase this power can vary widely and is also affected by federal and state requirements.

The feed-in tariff (FIT) is a common type of buyback rate. A FIT consists of a contract between the utility and the renewable generator to purchase the output of the renewable generation capacity at a fixed rate for a fixed period of time (often 10 to 20 years). The FIT price is often higher than the utility's retail rate, and it remains fixed for the length of the contract period even if the retail rate fluctuates. This fixed price provides a degree of certainty that net metering cannot match with regard to the payback period of the customer's energy system.

FITs are a powerful tool for incentivizing renewable development, and they can jump-start a renewable industry faster and more effectively than many other policy instruments. However, it is precisely for this reason that they must be designed carefully and flexibly, allowing them to adjust to fluctuations in the industry and the markets they affect. This is a lesson learned from examples such as in Spain, where the government offered a highly attractive FIT rate in 2007 that incentivized installations far beyond the capacity targets (Voosen 2009). The government quickly reduced the tariff incentives a year after the start of the program, and they suspended the FIT altogether in 2012 to contain costs to the government and other utility customers (EIA 2013). To avoid such boom and bust cycles and to provide stability for both utilities and the clean energy technology industry, FITs can be designed with features such as capacity caps, incentives that decline with installed capacity levels, or incentives that are linked to market conditions.

Electric vehicle rates. As battery-powered electric vehicles (e.g., Tesla Model S, Nissan Leaf) and plug-in hybrid electric vehicles (e.g., Chevrolet Volt) become more common, some utilities have begun offering rate plans (tariffs) designed specifically for households that charge electric vehicles. These tariffs usually employ a TOU structure to encourage electric vehicle owners to charge their cars during off-peak hours and thus prevent peak load from increasing.

As of July 2014, 25 utilities scattered across 14 states have made electric vehicle-targeted rates available (Northeast Group 2014). These tariffs sometimes include "super off-peak" hours to encourage charging late at night (e.g., Georgia Power, 11:00 p.m. to 7:00 a.m.) (Georgia Power 2014). Others, such as the electric vehicle tariffs offered by Pacific Gas and Electric (PG&E), include an option to meter the electric vehicle charger separately from the rest of the home (PG&E 2014d). This enables electric vehicle owners to put the charger on a different rate plan from the rest of the house, taking advantage of low off-peak prices without incurring higher costs for electricity used elsewhere in the house during peak hours.

In Texas, where night-peaking wind power is abundant, the utility TXU Energy's "Free Nights" plan offers free electricity from 9:00 p.m. to 6:00 a.m. every day, albeit with rates higher than those of many other plans during the rest of the day (TXU Energy 2014). This arrangement enables electric vehicle owners to save money and charge their vehicles with renewably generated electricity, and it helps the utility by minimizing surplus generation from renewables during off-peak hours.

Data Access

Providing customers, utilities, third parties and others access to energy use information can be an important part of incentivizing energy efficiency, distributed renewable energy, and CHP. Each group has different data access considerations.

Commercial customers. Access to energy use data is critical for benchmarking energy use in commercial, administrative, and multifamily residential buildings. Benchmarking allows building owners and managers to understand their buildings' energy use, identify the best opportunities for improvement, and measure the impact of efficiency efforts. Metering can present a challenge, as a single meter might register the combined energy use for multiple buildings, or a large building might have multiple meters that need to be summed to obtain total building energy use. This may require technical upgrades on the utility's part. Regulators can play a role by mandating that utilities provide such data access to commercial building owners, especially if the benchmarking process is itself being undertaken due to a regulatory mandate (SEE Action 2013). Seven states (California, Colorado, Illinois, Oklahoma, Pennsylvania, Texas, and Washington) have passed laws mandating that utilities provide consumers with access to their own data (SEE Action 2012).

Customers on time-varying rates. Rate schedules that seek to reduce peak demand by shifting some usage to off-peak hours are much more likely to be effective if ratepayers can see how specific choices and actions affect their energy use—and consequently, their bills—at different times. The standard total monthly energy use found on most ratepayers' bills will not provide sufficient detail for them to evaluate how much impact a particular action had. Many utilities are providing customers new online energy management tools, in-home energy use displays, and programmable thermostats to provide customers with better access to their energy usage information and to help them manage their energy bills. More detailed information on energy use also makes it easier for customers to track the savings afforded by distributed renewable energy such as solar panels.

Utilities. Though the utility itself has access to data—provided that its metering infrastructure is sufficiently advanced—the utility may employ an outside company to help implement its energy efficiency or clean energy programs. That company will likely need at least partial access to energy use data in order to fulfill its role. Utilities typically include provisions for data security and limitations on data usage in their contractual arrangements with outside companies. Customer consent is typically not required; however, the state public utility commissions (PUCs) in Oregon and Vermont have established rules for data sharing when all customer billing and energy use data is shared (SEE Action 2012).

Third parties. From the perspective of third parties such as energy service companies, customer energy use data can be a valuable tool for identifying market opportunities and developing successful customer acquisition strategies. As discussed above, state regulators can exercise some control over the data that utilities can share with outside vendors. A key question is how much aggregate information the utility can share without obtaining consent from all the individual customers whose energy use is included in the total. This question is important to utilities due to the logistical expense of contacting customers to obtain consent, so several states have now passed standards governing when the need for consent is triggered. Vermont, for example, has established regulations that set minimum standards for size of the geographic area covered by the data, while Colorado has regulated the number of customers included in an aggregated data pool and their relative percent of the total energy use.

In situations where customers voluntarily provide their energy use data to third parties, there is again the potential for improper data usage and breach of privacy. In these situations, there are fewer direct actions regulators can take, but they can encourage third parties to provide privacy assurances and encourage customers to ask to see an official privacy policy (SEE Action 2012). For example, states could encourage third parties to voluntarily adopt the U.S. Department of Energy's (DOE's) Voluntary Code of Conduct, which includes concepts and principles regarding customer data privacy. [104]

Others. For researchers and policy-makers, energy use data aggregated by time period, geographic area, or demographic group can provide a valuable window into opportunities for energy efficiency or clean energy incentive programs on a larger scale (SEE Action 2012). However, requests for such data can raise customer privacy and utility cost concerns.

Designing Utility Rates and Providing Data Access to Support Energy Efficiency, CHP, and Clean Energy Goals

While there are a range of strategies available for encouraging customer investment in energy efficiency, distributed renewable energy, and CHP, states have found that having a supportive rate structure and complementary access to energy usage data can be critical to a customer making the business case and moving forward with investment. Similarly, ensuring that all customers benefit regardless of whether they directly participate in energy efficiency programming or invest in clean energy is important to maintaining long-term support for investments and policy goals. For this reason, it is important to understand the system-wide benefits of these investments and to address the unique perspectives and implications for each customer class. This section summarizes some key design issues, introduces the participants, and highlights how federal and state policies can interact with clean technology rates.

Key Design Issues

Utilities and regulators balance competing goals in designing rates. Achieving this balance is essential for obtaining regulatory and customer acceptance. Key design issues are described below.

Fairly Apportion Costs Among Customers

Utilities undergo formal processes to determine what share of their revenue will be received from each customer class. In regulatory proceedings, this process is often contentious, as each customer class seeks to

[104] DOE's Office of Electricity Delivery and Energy Reliability and the Federal Smart Grid Task Force facilitated a multi-stakeholder process to develop the Voluntary Code of Conduct. The Final Concepts and Principles, released on January 12, 2015, are available at http://www.energy.gov/sites/prod/files/2015/01/f19/VCC%20Concepts%20and%20Principles%202015_01_08%20FINAL.pdf.

pay less. This makes it difficult for utilities to propose rate designs that shift revenues between different customer classes. In redesigning rates to encourage energy efficiency, distributed renewable energy, and CHP, it is important to avoid unnecessary or inadvertent cost shifts between customer classes.

Maintain Rate Simplicity

The challenge for promoting energy efficiency is balancing the desire for rates that provide the right signals to customers with the need to have rates that customers can understand, and to which they can respond. Rate designs that are too complicated for customers to understand will not be effective at promoting efficient consumption decisions. Particularly in the residential sector, customers might pay more attention to the total bill than to the underlying rate design.

Mandatory vs. Voluntary Rates

A key design issue for utilities and policy-makers is whether the energy efficiency, distributed renewable energy, or CHP customer remains on a standard utility rate, can elect to move to a voluntary optional utility rate, or is required to take service under a special mandatory rate.

The use of voluntary rates provides more flexibility to incentivize clean energy, but it also introduces a potential free rider effect. For example, hot summer days are typically a peak usage period, so a utility might incentivize people to reduce their peak energy usage by offering a voluntary TOU rate with high summer midday prices and lower prices at other times of the year. These rates could encourage the installation of onsite solar, which would lower customers' net energy usage the most during sunny summer days. However, the same rate would also benefit a residential customer who commutes to work and is not home during the day, even if they do not install onsite solar. This is an example of the free rider effect. One partial solution would be to make the optional rate only available to customers who own onsite solar; however, in that case, a commuter customer with onsite solar could still see a large portion of their savings come from switching to the optional rate rather than from their onsite solar.

Mandatory special rates can be customized and targeted to energy efficiency, distributed renewable energy, and CHP customers. This design freedom can also lead to controversy, though, as targeting could be viewed as discriminatory *against* the technologies (i.e., high standby rates) or *for* clean technology (i.e., high FIT). Whereas standard utility rates are anchored by existing rate levels and utility rate increase percentages, special rates may be so unique that they have no clear benchmarks for deciding reasonableness.

Compensating Customers Who Generate Electricity

Another key design issue is how to compensate customers who generate their own electricity, such as through distributed renewables or CHP. These customers may be compensated through bill reductions due to their lower net energy usage, or they may be paid directly for their electricity output. As discussed above, the bill reduction method adds uncertainty into the customer's purchase decision because of unknown future changes in utility rates. Conversely, the use of set payment methods, such as FIT contracts with 20-year fixed prices, can burden utilities and other utility customers if the value of the distributed renewable generation drops.

Cost of Implementation

All of these designs will have implementation implications. For example, rates like RTP will have extensive data requirements, which raise the issue of how utilities will recover the costs incurred by information technology updates associated with making detailed energy data available to consumers. The range of recovery options includes spreading the costs to all customers via general operating expenses; adding a surcharge to customer bills; folding the costs into other project budgets, such as advance meter deployments and/or customer programs; or charging customers for data access.

Participants

Given the issues described above, changing rate design is often a contentious process involving lengthy workshops, settlement discussions, or litigated proceedings. This section introduces the major participants in the rate-setting process.

- *State PUCs.* Rates typically are approved by the state PUC during a utility rate filing or other related filing. The PUC staff are the focal point for evaluating costs and benefits to generators, utilities, consumers, and society as a whole. Many PUCs conduct active rate reviews in order to maintain consistency with changing policy priorities.
- *Utilities.* Utilities play a critical role in rate-setting. Their cost recovery and overall economic focus have historically revolved around volumetric rates that reward the sale of increased amounts of electricity. Anything that reduces electricity sales (including energy efficiency, distributed renewables, and CHP) also reduces utility income and may make it more difficult to cover fixed costs if the fixed components of existing tariffs are not calculated to match utility fixed costs. This creates a disincentive for utilities to support such projects. New ways of setting rates (e.g., decoupling or performance-based rates) can make utility incentives consistent with those of energy efficiency developers and policy-makers. (For more information on policies that can serve as utility incentives for clean energy, including decoupling utility profits from electric sales, see Section 7.2, "Policies That Sustain Utility Financial Health.")
- *Renewable energy and CHP project developers.* Project developers establish clean technology benefits and the policy reasons for developing rates that encourage their application. They participate in rulemakings and other proceedings, where appropriate.
- *Regional transmission organizations or independent system operators.* While not directly involved in utility rate-setting, these entities manage electricity infrastructure in some regions of the country. They interact with CHP and renewable generators and may also be involved in ratemaking discussions.
- *State energy offices, energy research and development agencies, and economic development authorities.* These state offices often have an interest in encouraging energy efficiency, distributed renewables, and CHP as a strategy to deliver a diverse, stable supply of reasonably priced electricity. They may be able to provide objective data on actual costs and help balance many of the issues that must be addressed.
- *Ratepayer advocates.* Many state governments have staff dedicated to representing ratepayer interests in rate case proceedings. These staff may be located within state PUCs (as in California), in the Office of the Attorney General (as in Kentucky, Arkansas, Alabama), or elsewhere within the state government (NASUCA 2014).

Interaction with Federal Policies

PURPA section 210 regulates interactions between electric utilities and renewable/CHP generators that are considered "qualifying facilities." PURPA played a role in structuring these relationships, most notably in conceptualizing rates based on avoided cost. In noncompetitive markets, qualifying facility status may be the only option for non-utility generators to participate in closed electricity markets. In those jurisdictions with open electricity wholesale markets, generators no longer need to attain qualifying facility status to participate in wholesale markets. Historically, PURPA has not spurred large growth in renewable generation because the definition of "avoided cost" was taken to mean the cost of the cheapest marginal power source available. This was usually combined cycle natural gas, whose low cost was not enough to support renewable growth.

In October 2010, the Federal Energy Regulatory Commission (FERC) issued a ruling that changed the definition of avoided cost. Due to the fact that the original definition failed to stimulate much renewable energy growth, many states subsequently enacted RPSs. In its 2010 ruling, FERC recognized that an RPS changed the value of renewable generation because that value became dependent on more than just the cost of the cheapest marginal generation. FERC's ruling therefore authorized states to require higher payments to qualifying facilities, allowing for payments large enough to make renewables more economically feasible (NREL 2011).

More indirectly, the federal government plays a role in the evolution of electricity rate structures through the provision of analysis, funding, and research. The National Renewable Energy Laboratory (NREL) has produced numerous reports exploring the economics of various renewable energy technologies (NREL 2014). Some of these reports focus explicitly on the relationship between electricity rate structures, electricity prices, and economic feasibility of the technology in question—often solar PV.[105] NREL reports are freely available to the public, and may therefore be used by state officials and utilities during the ratemaking process.

The federal government also provides funding for projects that catalyze grid modernization, and this modernization process can profoundly affect data access and future rate structures. For example, the Smart Grid Investment Grants (SGIG) program, funded by the American Recovery and Reinvestment Act of 2009, distributed $3.4 billion in funds for grid modernization projects. Two of the eligible project categories were AMI and computer systems (DOE 2012b). Both of these technology classes enable a broader choice of rate structures by providing utilities and their customers with a more detailed, real-time picture of energy use. Lawrence Berkeley National Laboratory is also leading customer behavior research projects leveraging SGIG deployments. Similarly, the DOE's most recent loan guarantee solicitation for Renewable Energy and Efficient Energy Projects, released July 3, 2014, specifically names advanced grid integration and storage as a preferred project category (DOE 2014).

Interaction with State Policies

Designing utility rates to support energy efficiency, distributed renewable energy, and CHP can be coordinated with other state policies:

- Ratemaking issues are often closely tied to the structure of the state's electric regulatory authority. States regulate supply and delivery of vertically integrated IOUs. In restructured "retail choice" states, where the utility supply has been deregulated and is now separate from the delivery company, consumers can choose from whom they buy their energy. Utilities in restructured states often have exit fees, and they may also be sensitive to the need to facilitate clean technologies to prevent customers from looking to alternate electricity providers. Furthermore, customers in states with retail choice suppliers may have an opportunity to choose rate structures that are not subject to state regulatory approval. For example, Direct Energy in Texas offers a program called the "Meridian Plus" plan, which requires customers to lock in a fixed-rate electricity price for 24 months at a price that is currently above the variable and short-term pricing options. In exchange for the slightly higher price, customers gain price certainty in addition to devices and services that help them reduce their energy usage. Under the rate plan, Direct Energy offers smart thermostat installation and smartphone integration to improve customer heating and cooling

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105 E.g., "Impacts of Commercial Electric Utility Rate Structure Elements on the Economics of Photovoltaic Systems," http://energy.gov/sites/prod/files/2014/11/f19/46782.pdf; "Impacts of Regional Electricity Prices and Building Type on the Economics of Commercial Photovoltaic Systems," http://www.nrel.gov/docs/fy13osti/56461.pdf.

decisions, as well as a seasonal heating, ventilating, and air conditioning maintenance checks to improve equipment performance (Direct Energy 2014).

- States have explored decoupling utility revenues from the volume of electricity sold. This issue addresses the inherent conflict when a utility has an incentive to maximize sales (the throughput incentive) instead of promoting demand-side options such as energy efficiency and onsite generation. Decoupling can be important when examining clean technology rates. States have also considered allowing utilities to recover more of their costs through monthly bill charges rather than through rate structures applied to the volume of electricity consumption. However, such approaches could lessen the incentive for energy efficiency and customer-sited clean energy. (For more information on decoupling and other mechanisms for adjusting utilities' incentives, see Section 7.2, "Policies That Sustain Financial Health.")
- If an RPS is in place, high standby rates, exit fees, and non-bypassable charges may unintentionally render clean energy projects uneconomical. (See Chapter 5, "Renewable Portfolio Standards.")
- As part of disaster preparedness planning, some states include grants or other incentives for DG installations that can support critical pieces of infrastructure during blackouts. CHP plants are typically included among the eligible technologies.[106]

Program Implementation and Evaluation

Administering Body

State PUCs are responsible for rate oversight and approval for IOUs and some cooperatively and municipally owned utilities. If not under PUC oversight, local boards oversee cooperatively and municipally owned utilities. In restructured (retail choice) states, competitive energy suppliers can set their own generation rates. However, PUCs in restructured states still have authority over the rates a regulated utility will charge for providing electricity to customers who do not receive their service from competitive suppliers. PUCs in restructured states also retain authority over other components of electricity rates, such as electricity delivery charges and collection of public benefits funds.

Evaluation and Oversight

States are attempting to ensure that rates are based on accurate cost and benefit measurements of energy efficiency, distributed renewable energy, and CHP; they are also attempting to ensure that such costs and benefits are distinct from those that are already captured in the otherwise applicable rate classification. Additionally, states are starting to explore ways to ensure that rates reflect the extent to which energy efficiency, distributed renewable energy, and CHP can benefit the rest of the electricity grid and under what conditions. These benefits include increased system capacity, potential deferral of transmission and distribution investment, reduced system losses, improved stability from reactive power, and voltage support. In restructured states, these benefits may be external to the regulated utility, but it is important that rates capture these elements to ensure optimal capital allocation by both regulated and unregulated parties.

Conducting evaluations of a state rate offering may require funding and other resources be made available at the utilities and state PUCs. Such resources will also allow for the monitoring of rate impacts on energy efficiency, distributed renewable energy, and CHP and across customers. Significant, unanticipated, or adverse impacts may be identified, which could then be addressed through modifications such as adjusting the rate

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[106] For example, see Connecticut's Microgrid Grant and Loan Pilot Program at http://www.ct.gov/deep/cwp/view.asp?a=4120&Q=508780.

design or altering the rate qualification criteria. For example, several states have now initiated proceedings to move beyond net metering and develop new rate structures for energy efficiency, distributed renewable energy, and CHP that are more closely tied to DG's estimated value (CPUC 2014).

State Examples

Inclining Block Rates

California

Each of the California IOUs uses inclining block rates for their default residential customers. For example, PG&E has an inclining block rate with four tiers based on cumulative energy use in a given month. As customers use less energy due to installation of clean energy technologies, they see bill savings at their marginal tier energy rate. For example, in 2014, the Tier 4 residential rate is about 17 cents per kWh higher than the Tier 1 energy rate. This structure gives larger energy users larger incentives to adopt clean energy technologies than smaller users because the large users will have higher marginal tier energy rates.

Residential customers under net energy metering rates are also indirectly subject to the inclining block rates because the inclining block rates are the foundational "otherwise applicable schedule" upon which the residential net energy metering rates are based. An inclining block rate provides strong incentives for DG systems because these systems cancel out the most expensive kWh first.

New York

Consolidated Edison's (Con Edison's) default residential rate is a blend of flat and inclining block rates. The energy rate is flat for October through May. In the summer months, the rate switches to an inclining block rate with Tier 2 being about 1.3 cents per kWh higher than Tier 1. Tier 2 applies to all kWh in the summer months in excess of 250 kWh. As with PG&E, Con Edison's inclining block rate also provides the foundation for its net energy metering rate.

Time-Varying Rates

California

PG&E uses TOU energy rates for its business customers. The general TOU rate uses five TOU periods (two in the winter and three in the summer). While TOU rates have long been common for large commercial and industrial customers, the California Public Utilities Commission (CPUC) mandated the transition for all business customers to TOU rates. Small and medium business customers began transitioning in November 2012 (PG&E 2014e).

Inclining block is the default rate for residential customers, with inclining block TOU rates as a voluntary option. The inclining block TOU rate is the mandatory rate for all net energy metering customers starting service on or after January 1, 2007. The inclining block TOU rate has peak and off-peak rates and four tiers. The higher the tier usage, the higher the energy rate, and usage in the peak period receives a higher energy rate. Peak and off-peak usage is assigned to tiers on a pro-rata basis. For example, if 20 percent of a customer's usage is in the peak period, then 20 percent of the total usage in each tier will be treated as peak usage and 80 percent of the total usage will be treated as off-peak usage (PG&E 2014b).

New York

Con Edison offers TOU rates as voluntary rate options. The voluntary TOU option is promoted for electric vehicle customers (see description under *Electric Vehicle Rates* below) but is also available to non-electric vehicle customers, albeit without the bill guarantee that is available to registered electric vehicle users. Con Edison customers can also choose to obtain supply from alternate providers that can offer different pricing options.

Standby Rates

California

California Senate Bill 1-28 (passed in April 2001) required utilities to provide DG customers with an exemption from standby reservation charges. The exemptions applied for the following time periods:

- Through June 2011 for customers installing CHP-related generation between May 2001 and June 2004.
- Through June 2006 for customers installing non-CHP applications between May 2001 and September 2002.
- Through June 2011 for "ultra-clean" and low-emission DG customers, 5 MW and less, installed between January 2003 and December 2005.

After Bill 1-28 expired, standby rates were left to be incorporated into utilities' general rate cases. However, CPUC still requires that utilities exempt DG systems from fixed standby charges as long as the DG systems provide physical assurance (EPA 2014).

New York

Under General Rule 20.3.1, Con Edison exempts customers from standby rates if 1) their onsite generation nameplate capacity is less than 15 percent of their maximum demand, 2) they take service on energy-only residential or small commercial rates, or 3) they have a contract demand less than 50 kW. In addition, General Rule 20.3.2 allows customers to opt out of the standby rate if they install a designated technology between July 29, 2003, and May 31, 2015. A customer with a designated technology must meet the following criteria (Con Edison 2012):

- Has an on-site generation facility that: 1) exclusively uses one or more of the following technologies and/or fuels: fuel cells, wind, solar thermal, PVs, sustainably managed biomass, tidal, geothermal, or methane waste, or 2) uses small, efficient types of CHP generation that do not exceed 1 MW of capacity in aggregate and meets eligibility criteria that were approved in the order of the New York State Public Service Commission, dated January 23, 2004, in Case 02-E-0781; and
- Has a contract demand of 50 kW or greater and has onsite generation equipment having a total nameplate rating equal to more than 15 percent of the maximum potential demand from all sources.

Exit Fees

California

There are several types of exit and transition fees in the California market, and they are handled differently depending on the specific utility. Fee exemptions exist for the following classes of renewable and CHP systems:

- Systems smaller than 1 MW that are net metered or are eligible for CPUC or California Energy Commission incentives for being clean and super-clean (PG&E 2014a).

- Ultra-clean and low-emission systems that are 1 MW or greater and comply with the California Air Resources Board's 2007 air emission standards (PG&E 2014a).
- Zero emitting, highly efficient (> 42.5 percent) systems built after May 1, 2001.

Illinois

Illinois ended exit fees for stranded costs on December 31, 2006. Prior to that end date the rule was fairly stringent and specific about the instances that triggered such a fee. The rule did, however, provide an exemption for DG and CHP. A departing customer's DG source had to be sized to meet its thermal and electrical needs with all production used on site (Illinois 2014).

Net Energy Metering

Georgia

In 2001, the state government of Georgia passed the Georgia Cogeneration and Distributed Generation Act, which requires all utilities to offer net metering to their customers. The Act contains the following provisions:

- Only solar PV, wind, and fuel cell systems are eligible.
- System size must not exceed 10 kW for residential systems or 100 kW for non-residential systems.
- The aggregate capacity of all the net metered systems in a utility's service territory must not exceed 0.2 percent of the utility's peak load from the previous year.
- If a customer's net metered system produces surplus electricity in any given month, the surplus is credited to the customer's bill for the following month. Surplus generation is credited at a value set by the Georgia Public Service Commission, as opposed to the full retail rate used by many states (DSIRE 2014a).

Connecticut

Connecticut provides net metering for a wide variety of technologies, including solar PV, solar thermal, wind, fuel cells, municipal solid waste, landfill gas, hydroelectric, wave and tidal energy, ocean thermal, and CHP. Connecticut's program has the following provisions:

- Systems must not exceed 2 MW in size, but there is no cap on the aggregate capacity of net metered systems.
- Excess generation is rolled over each month as kWh credits at full retail value.
- At the end of each year, customers are paid the wholesale value of any accumulated kWh credits.
- Net metered facilities are eligible to earn renewable energy certificates, which the system owner can sell to utilities to help the utilities meet their RPS commitments.

Connecticut also offers virtual net metering for certain types of facilities. Virtual net metering allows additional customers besides the owner to receive credits for the electricity generated by a net metered system. This can be extremely helpful for large institutions that have multiple meters (e.g., a large farm or state government complex), because the output from a net metered system can be shared among all the institution's electricity accounts while being wired to only one meter. This also allows multiple farms or government institutions to share both the costs and the benefits of a DG system. DG systems that will be using virtual net metering may be up to 3 MW in size (DSIRE 2013).

New York

The state of New York offers net metering for distributed solar PV, wind, biomass, small hydroelectric, fuel cells, CHP, anaerobic digestion, and microturbine systems. New York's program has the following provisions:

- Maximum eligible system size varies by technology and sector, ranging from 10 kW for residential CHP systems to 2 MW for non-residential solar, wind, and small hydroelectric systems.
- Net excess generation is rolled over to the next month's bill at retail rate, with the exception of CHP and fuel-cell systems. For these two types of systems, excess generation is rolled over only at the avoided-cost rate.
- Long-term treatment of accumulated credits again varies, but depending on technology and customer sector, the credits are either rolled over from month to month indefinitely or paid to the customer at the avoided-cost rate at the end of each year.
- Aggregate capacity of net metered systems cannot exceed 3 percent of the demand for electricity generated from solar, fuel cells, micro-hydro, and agricultural biomass in a designated benchmark year (2005) (DSIRE 2014b).

California

California's net metering program dates back to 1996, and in the original form it was only available to wind and solar systems. The program has since been updated extensively, now covering landfill methane, biomass, geothermal, fuel cells, small hydroelectric, wave and tidal power, ocean thermal power, anaerobic digestion, and biogas. California's program has the following provisions:

- Systems may be up to 1 MW in size, with exceptions for up to 5 MW systems granted to municipal governments.
- Net excess generation rolls over monthly at the retail rate, and customers can choose whether to roll it over indefinitely or sell the accumulated credits at the 12-month average spot market price (hours of 7:00 a.m. to 5:00 p.m. only) at the end of each year.
- The aggregate capacity of net metered systems was originally set at 5 percent of peak demand, but differences in utility methodology for calculating peak demand led the state legislature to set absolute caps on the number of MW of net metered capacity for each of California's three largest electric IOUs. The caps are 607 MW for San Diego Gas and Electric, 2,240 MW for Southern California Edison, and 2,409 MW for PG&E. The net metering program expires when each utility reaches its cap or on July 1, 2017, whichever comes first.
- California is one of a few states that are actively developing alternatives to net metering in an attempt to avoid the cost shifts that net metering produces as the aggregate capacity of net metered systems increases. The CPUC is currently conducting a formal proceeding to gather stakeholder input on potential programs and rate structures that can replace net metering when the program expires.

Feed-in Tariff

Hawaii

In 2010, Hawaii instituted a FIT for a variety of renewable energy technologies. Owners of eligible DG installations can sign 20-year contracts with one of the three IOUs in Hawaii, wherein the utility agrees to purchase the output of the DG system at a fixed per kWh price. Eligible technologies include solar PV, concentrating solar thermal, in-line hydroelectric, on-shore wind, and all other renewable technologies that qualify for Hawaii's RPS. The FIT price varies with the technology type and the system size. Concentrating solar plants command the highest FIT rates, followed by small (≤20 kW) solar PV and in-line hydroelectric systems (DSIRE 2014c).

Electric Vehicle Rates

Georgia

Rate schedules specifically for electric vehicles vary by utility rather than state. The plug-in electric vehicle tariff offered by Georgia Power is a good example of a residential electric vehicle rate. Each day is divided into three periods: on-peak, off-peak, and super off-peak. On-peak hours are from 2:00 p.m. to 7:00 p.m. on summer weekdays, June through September. These hours have the highest rates because this is when utilities have to deal with peak demand and thus wish to discourage the charging of electric vehicles. By contrast, the super off-peak hours of 11:00 p.m. to 7:00 a.m. have the lowest rates, because this is when aggregate demand is minimized and charging electric vehicles puts a minimal amount of stress on the grid. Regular off-peak hours fill the gap between on-peak and super off-peak hours, and their price correspondingly falls between the two (Georgia Power 2014). For customers who choose the plug-in electric vehicle rate, the charging load from their electric vehicle is aggregated with the rest of their household load in their total hourly meter reading. Though choosing this rate will save them money on the electric vehicle portion of their electricity load (assuming they charge during super off-peak hours), these customers may see their total bill increase from what it was under a flat rate if their household has high electricity demand for other uses during peak hours.

California

PG&E offers electric vehicle rates that incentivize charging between 11:00 p.m. and 7:00 a.m. (off-peak). Prices are lowest during these hours, and highest from 2:00 p.m. to 9:00 p.m. (peak). All other hours, designated "partial-peak" hours, have a price that falls between peak and off-peak prices. The partial-peak category applies only on weekdays; on weekends the partial-peak hours are absorbed into the off-peak category and use the off-peak rate (PG&E 2014c).

The most unique feature of PG&E's electric vehicle rate program is that it gives electric vehicle owners the option to meter their charging station separately from the rest of their home. This means that the vehicle charger and the rest of the home can be on different rate schedules, which is advantageous for electric vehicle owners who use large quantities of electricity elsewhere in their homes during peak hours. If they meter their charger separately and put only the charger on the electric vehicle rate, such vehicle owners can still subscribe to a flat rate schedule for the rest of their homes and avoid the high peak-hour charges they would receive if the whole house were on the electric vehicle schedule.

New York

Con Edison offers an off-peak rate of only 1.34 cents per kWh for usage between midnight and 8:00 a.m. under the voluntary TOU rate (Con Edison 2014). Unlike the PG&E rate, Con Edison's customer places their entire home on the TOU rate. Because the peak rate under TOU is higher than the standard rate, this introduces some risk that customers could pay more under the TOU rate than under the standard rate. To address this uncertainty, the voluntary TOU rate offers a price guarantee for customers who register a plug-in electric vehicle with Con Edison. Under the price guarantee, during the first year after registering their vehicle, plug-in electric vehicle customers are assured that they will not pay more over the course of the year than they would have paid under the standard rate.

What States Can Do

Action Steps for States

States have chosen a wide variety of approaches and goals in developing their rates. Suggested action steps are described below for two groups of states: those that have already begun to address utility rates to incentivize energy efficiency, distributed renewable energy, and CHP, and those that have not.

States That Have Addressed Rates and Data Access

States that have established rate design and data access policies have found that it is important to identify and mitigate issues that might adversely affect the success of the rates. States can:

- Monitor utility implementation of rates. By doing so, a state may want to confirm that the rates are being properly communicated to customers and that the rates are not serving as unintentional barriers to energy efficiency, distributed renewable energy, and CHP adoption.
- Explore policies to give customers the data format and tools they may need to manage their energy bills.
- Monitor the impact of the rates on energy efficiency, distributed renewable energy, and CHP, as well as across customers. States have addressed significant, unanticipated, or adverse impacts through modifications such as adjusting the rate design or altering the rate qualification criteria. In considering the impact of clean energy technologies, a state may find it useful to consider the wide breadth of benefits of such technologies, and not focus solely on near-term economic impacts.
- Periodically review the evolving technologies to gauge whether rate or data access modification might be warranted. For example, in California, inclining block residential rates have long been lauded for promoting the adoption of energy efficiency. However, the recent surge in PV installations that produce more electricity than the homeowner can use at certain times of the year is raising questions about whether the inclining block rates are providing the correct incentives for PV installations under the net energy metering program.

States That Have Not Addressed Rates and Data Access

Experience from those states that have implemented rates to promote energy efficiency, distributed renewable energy, and CHP indicates that political support from PUC officials and staff is a key first step for establishing effective rates. Once support for these rates has been established, states have found that the next step is to facilitate discussion and negotiation among key stakeholders toward appropriate rate design. More specifically, states can:

- Ascertain the level of general interest and support for energy efficiency, CHP, and/or distributed renewable energy among public office holders and the public. If awareness is low, consider implementing an educational program about the environmental and economic benefits of accelerating development in order to gain policy and public support.
- Identify existing or pending policies that might be significant drivers for new energy efficiency, distributed renewable energy, and CHP. Rate revisions or new rate designs can then be presented and negotiated in the context of being consistent with and enabling these existing policy goals.
- Establish a working group of interested stakeholders to consider design issues and develop recommendations for favorable rates.
- Open a generic PUC docket to explore actual costs and system benefits of energy efficiency, distributed renewable energy, and CHP in order to inform rate reasonableness.

Information Resources

Federal Resources

Title/Description	URL Address
The U.S. Environmental Protection Agency's (EPA's) CHP Partnership. A voluntary program that seeks to reduce the environmental impact of energy generation by promoting the use of CHP. The Partnership helps states with resources for policy development (energy, environmental, economic) to encourage energy efficiency through CHP and can provide additional assistance to states in assessing and implementing reasonable rates.	http://www.epa.gov/chp/
State and Local Energy Efficiency Action Network (SEE Action) Customer Information and Behavior Working Group. This Working Group has issued a report which discusses key state and local issues relating to customer access to energy usage data.	https://www4.eere.energy.gov/seeaction/working-group/customer-information-and-behavior
Guide to the Successful Implementation of State Combined Heat and Power Policies. The SEE Action Industrial Energy Efficiency and CHP Working Group has issued a report that informs state utility regulators and other state policy-makers with actionable information to assist them in implementing key state policies that impact CHP.	https://www4.eere.energy.gov/seeaction/publication/guide-successful-implementation-state-combined-heat-and-power-policies
DOE's CHP Technical Assistance Partnerships (CHP TAPs). CHP TAPs promote and assist in transforming the market for CHP, waste heat to power, and district energy technologies/concepts throughout the United States.	http://www.energy.gov/eere/amo/chp-technical-assistance-partnerships-chp-taps
Consumer Behavior Studies. DOE is working with several SGIG award recipients who are conducting special studies to examine acceptance, retention, and response of consumers involved in time-based rate programs that include AMI and customer systems such as in-home displays and programmable communicating thermostats.	https://www.smartgrid.gov/recovery_act/consumer_behavior_studies
The National Action Plan for Energy Efficiency. A federally facilitated, private-public initiative that produced a number of resources on energy efficiency. In particular, the Customer Incentives for Energy Efficiency Through Electric and Natural Gas Rate Design briefing provides a foundation on the relationship between rates and energy efficiency.	www.epa.gov/eeactionplan http://www.epa.gov/cleanenergy/documents/suca/rate_design.pdf

Resources on Ratemaking

Title/Description	URL Address
The Regulatory Assistance Project (RAP). RAP has published several reports and presentations on utility rate design issues—for example, "Designing Distributed Generation Tariffs Well: Ensuring Fair Compensation in a Time of Transition." The RAP Library allows users to search by Rate Design within the Energy Efficiency/ Resource Planning Topic search.	http://www.raponline.org http://www.raponline.org/press-release/designing-distributed-generation-tariffs-well-ensuring-fair-compensation-in-a-time-of
Rate Design for the Distribution Edge. This report from the Rocky Mountain Institute's Electricity Innovation Lab discusses retail electricity pricing issues as use of distributed energy resources increases.	http://www.rmi.org/PDF_rate_design
Standby Rates for Customer-Sited Resources: Issues, Considerations, and the Elements of Model Tariffs. This EPA report provides background	http://www.epa.gov/chp/documents/standby_rates.pdf

Title/Description	URL Address
information on rate design and the economics of DG, then delves specifically into the topic of standby rates.	
California Net Energy Metering Ratepayer Impacts Evaluation. This study commissioned by the CPUC evaluates the net monetary impact that net metering has on DG owners, non-owner ratepayers, and society as a whole.	http://www.cpuc.ca.gov/NR/rdonlyres/C311FE8F-C262-45EE-9CD1-020556C41457/0/NEMReportWithAppendices.pdf

Other Resources

Title/Description	URL Address
Database of State Incentives for Renewables and Efficiency (DSIRE). Online database of information on incentives and policies that support renewables and energy efficiency in the United States. DSIRE is operated by the N.C. Solar Center at N.C. State University, with support from the Interstate Renewable Energy Council, Inc. DSIRE is funded by DOE.	http://www.dsireusa.org
Regulatory Requirements Database for Small Generators. Online database of regulatory information for small generators. Includes information on standby rates and exit fees, as well as environmental permitting and other regulatory information.	http://www.eea-inc.com/rrdb/DGRegProject/index.html
The Combined Heat and Power Association (CHPA). CHPA brings together diverse market interests to promote the growth of clean, efficient CHP in the United States.	http://chpassociation.org
Electricity Transmission: A Primer. This RAP publication was prepared for the National Council on Electric Policy in connection with the Transmission Siting Project. The primer is intended to help policy-makers understand the physics, economics, and policies that influence and govern the electric transmission system.	http://energy.gov/oe/downloads/electricity-transmission-primer

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7.5 Maximizing Grid Investments to Achieve Energy Efficiency and Improve Renewable Energy Integration

Policy Description and Objective

Summary

State have found that the U.S. electric grid has significant potential to deliver energy efficiency and support renewable energy integration if technology and infrastructure investments are made and managed with these goals in mind. As electricity is transmitted across long distances and then distributed by underground or overhead wires to our homes and businesses, it undergoes a number of conversions and during each conversion some energy is lost as heat.[107] The U.S. Energy Information Administration estimates that on average 7.5 percent[108] of the electricity produced to serve customers is lost in transmission and distribution, with losses ranging from 5 to 13 percent depending on location (Wagner et al. 1991, as cited in DOE 2012).[109] Modern grid investments can provide grid operators with tools to better visualize and control conditions across the electric system, enabling them to reduce system losses, better accommodate intermittent renewable resources, and help customers use less energy.

State-regulated transmission and distribution investments have traditionally been made with a goal of providing economic, reliable service that alleviates congestion, allows recovery from outages, and expands to meet new or growing loads. While these remain primary goals, states also are working to encourage investments that are planned and managed to increase system energy efficiency, anticipate growth in renewable resources, and deal with related issues of balancing utility revenue requirements with customer rates. This section focuses on what states and public utility commissions (PUCs) are doing—primarily at the distribution level (i.e., actions that do not involve interstate transmission planning)—to realize clean energy benefits from the electric grid.

Objective

Enabled by new and emerging technologies coupled with aging transmission and distribution systems, states are finding that if intentionally designed and managed, modern grid investments will not only provide necessary grid services but also deliver energy efficiency benefits and better accommodate renewable resources. Since many of these investments will last for 15 to 50 years, ensuring that modern grid investments are planned and managed with these objectives in mind is an important policy and planning goal.[110] While not captured neatly by any single mechanism, these objectives are nonetheless being advanced through interrelated policies and state and PUC decisions throughout the nation. This section provides state policymakers and interested stakeholders with background on emerging opportunities and steps that can be taken to lay groundwork for future grid investments to support greater energy efficiency and renewable energy penetration.

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107 Weather and other physical factors also contribute to line losses.

108 Line losses estimate is based on the historical difference between total net generation (minus direct use) and retail sales of electricity, as cited in the Clean Power Plan (EPA 2013) and derived from EIA (2012).

109 Nearly all of these losses are physical in nature (as opposed to theft, for example).

110 See, for example, BPA (2010).

Benefits

Maximizing modern grid investments to increase transmission and distribution system efficiency and support renewable generation integration has the potential to deliver significant environmental benefits:

- Pacific Northwest National Laboratory estimates that a comprehensive nationwide effort to better manage distribution system voltage could reduce annual energy consumption by 3.2 percent and reduce related carbon dioxide emissions by more than 63 million tons (PNNL 2012).[111]
- Grid investments could also enable greater integration of renewable energy resources and deploy complementary resources such as storage or demand response during periods when renewable resources wane (e.g., when solar production is interrupted due to cloud cover).
- Strategically located renewable resources, energy efficiency investments, and demand response capabilities can be targeted to alleviate grid congestion and defer capital investments. The flexibility of these resources can reduce the need to dispatch economically inefficient generation resources. Conventional generation resources also often need advanced notice to come online and need to run longer once started, even if periods of peak electricity demand are short. Storage and demand response do not usually need the same advance notice.

In addition, the ability to deliver energy efficiency and improve the integration of distributed renewables provides additional benefits for making the business case for modernizing electricity distribution systems.

Technical Background on Key Opportunities

Modern grid investments can enable better visibility into grid conditions throughout the distribution system, can allow two-way communication between the utility and customers (or their devices), and can enable automation to respond to grid conditions in real time. However, no single technology or combination of technologies delivers modern grid benefits. The way technologies and grid assets are managed is critical to achieving the promise of a modern grid. This section provides a technical overview of some of the energy efficiency and renewable energy benefits that states can realize if modern grid investments are planned for and managed with these resources in mind.[112]

Energy Efficiency Opportunities

Voltages in the transmission and distribution system can be adjusted to reduce system losses and/or to reduce customer load level to manage peak demand or to achieve broader energy efficiency benefits. Customer meter data also can be used strategically by grid operators, energy efficiency program managers, and customers to reduce consumption. These interrelated opportunities are discussed below:

- *Improved voltage management.* Throughout the United States, electricity is required to be delivered to most customers within a narrow range of voltages. For example, residential customer voltage is typically between 114 and 126 volts (for normal 120-volt service).[113] Delivering electricity closer to the lower end of

[111] Technical potential based on feeder modeling of representative high-value circuits; does not address time horizon for achievability.

[112] A fully integrated modern grid is likely to enable greater potential for cost-effective energy efficiency and renewable energy opportunities from smart grid and advanced microgrid technologies. The *Guide to Action* focuses on some of the better-established, nearer=term opportunities that states can realize if grid investments are planned for and managed with energy efficiency and renewable energy goals in mind.

[113] ANSI C84.1, “Electric Power Systems and Equipment—Voltage Ratings (60 Hertz),” specifies the nominal voltage ratings and operating tolerances for 60-hertz electric power systems above 100 volts.

this voltage range can save customers energy, because some equipment operates more efficiently at lower voltage (e.g., closer to 120 volts). For example, voltage reduction of incandescent lighting will generally reduce waste heat and therefore save energy. Not all customer devices will save energy by reducing voltage. For many water heaters, operating at the lower end the voltage range reduces immediate demand, but ends up using the same amount of energy to reach a target water temperature setting. Other loads, like today's fluorescent lamp ballasts, are likely to draw about the same amount of power regardless of voltage.[114]

Since the equipment used within homes, buildings, and industry varies, the potential for energy efficiency benefits also varies. In addition, some distribution circuits already operate in the lower band of voltage (i.e., 114–117 volts), further adding to the geographic variability of energy efficiency potential. Operating the transmission and distribution system at lower voltages to achieve energy efficiency benefits has historically been referred to as conservation voltage reduction (CVR). While CVR is a fairly mature approach and can be deployed without advanced technology, modern grid technologies enable a better understanding of the exact voltage at different points in the transmission and distribution system. Rapid communication with controls, as well as the ability to automatically respond to grid conditions, offers the potential for greater energy savings. The improved information also increases operational confidence among grid managers and regulators. While performance can vary by circuit, many utilities find 1 to 4 percent savings on initial deployment (PNNL 2010).

- *Improved reactive power management.* In alternating current (AC) systems—almost universally used in the United States to deliver electricity—current and voltage can get out of phase from equipment like motors and other devices that require magnetic fields to operate.[115] (This is referred to as reactive power and is measured in vars).[116] Since motors are ubiquitous in equipment found in factories, businesses, and homes, transmission and distribution system operators need to provide reactive power to maintain electric power flow. Some of the same technologies and strategies used to adjust system voltage can be used to better manage reactive power. Like voltage management, reactive power can be managed without modern grid technologies; however, modern grid technologies allow utilities to better monitor voltage and reactive power in real time along the entire delivery path from generator through transmission and distribution to the ultimate customers. Better communications and control equipment allows operators to adjust settings to control both factors all along the delivery path. This is a big improvement over adjusting settings manually and at infrequent intervals. Better reactive power management can reduce the fuel needed to operate the grid and can improve power quality.
- *Volt/var optimization.* When utilities manage and optimize both voltage and reactive power simultaneously, it is referred to as volt/var optimization. Since the flow of reactive power affects power system voltages, management of costs and operational performance of a power system may improve if voltage control and reactive power are well integrated (NEMA n.d.).
- *More efficient distribution transformers.* Distribution transformers are devices that are used to transfer current from one circuit to another and change the value of the original voltage or current as needed. A significant amount of all electricity network losses are due to distribution transformers. The use of more efficient medium voltage, liquid-immersed distribution transformers has the potential to yield large energy and monetary savings when projected over the products' lifetime. Despite substantial improvements made

[114] More information on power consumption responses to voltage is available in PNNL (2010) or Bokhari et al. (2014).

[115] Most devices that need magnetic fields will cause current and voltage to be out of phase. Besides motors, this will include some of the equipment used in transmission and distribution systems, such as transformers.

[116] Vars or var is the measure or reactive power in electric transmission and distribution systems. The term is derived from "volt-ampere reactive."

to distribution transformer efficiencies over recent years and new Federal efficiency standards set to take effect in 2016, EPA estimates that additional savings of up to 4 to 5 terawatt-hours per year can be achieved through identification and further deployment of the most efficient transformers available on the market today (EPA 2014).[117]

- *Strategic use of customer data/big data.* To customers, changes in utility meters may be the most noticeable new technology investment. These new meters, which are also referred to as smart meters or advanced metering infrastructure (AMI) meters, have sometimes caused controversy related to privacy concerns and billing accuracy among customers. Nonetheless, they have several operational advantages over conventional meters: they enable utilities to read meters without having to go to customer addresses, can facilitate same-day stop/start service when tenants move, and can help in detecting outages during storms to speed service restoration. AMI meters, along with sensors along distribution circuits, are giving utilities access to an unprecedented amount of data about their system and the customers they serve. For example, AMI meters can deliver consumption data at various intervals (e.g., hourly, 15-minute or 5-minute interval consumption data). Utilities are beginning to explore how to capture, store, analyze, and take advantage of "big data" to inform the following applications:
    - *Customer-level voltage and reactive power monitoring.* Modern AMI meters can be programmed to record voltages and reactive power flow periodically or on demand. This information can provide assurance that voltage and reactive power optimization efforts are performing as planned. For example, voltage readings can confirm that customers are receiving power at the intended voltage.
    - *Customer data services.* Utilities offer their customers energy usage information in varying levels of detail and through a variety of channels, such as customer bills, the Web, and automated data transfer services. The large-scale information technology projects that are often part of AMI and other grid modernization investments present an opportunity for utilities to incorporate the development of improved data access for customers (SEE Action 2013).
    - *Behavior-based energy efficiency programs.* Utilities are combining insights from behavioral science with energy use information to inform new energy efficiency program offerings. These behavior-based programs use economic and non-economic incentives, education, and feedback to change how people use energy. Utilities may combine multiple behavioral insights within an energy efficiency program offering such as peer comparisons, competitions, goal setting, and rewards (CEE 2014).
    - *Facilitating change in energy use in response to price signals.* Though not yet common in all deployments, some AMI meters can facilitate a two-way flow of information between the utility and the customer. When coupled with time-varying rates (see Section 7.4) that better reflect the price of electricity (which varies throughout the day), this information can encourage customers to shift consumption to lower-cost periods and support efforts to reduce peak demand (SEE Action 2014).
    - *Energy efficiency program planning, implementation, and evaluation.* AMI data can be analyzed for usage patterns to inform energy efficiency opportunities (for example, fluctuating usage may indicate that equipment is cycling on and off often, indicating that an appliance is improperly sized or ready for replacement). These data can inform program planning and targeting efforts. Some programs have begun pilot efforts to analyze data to provide virtual energy audits for interested customers.[118] Research is also underway to better understand how the more detailed energy usage data from AMI

[117] Given the aggregate energy losses of millions of medium voltage distribution transformers, EPA recently launched a stakeholder process to develop criteria for ENERGY STAR designation.

[118] Pacific Gas and Electric in California and Con Edison in New York are two such examples.

can be used to inform evaluation, measurement, and verification of energy efficiency programs (PEEC n.d.).

Renewable Energy Integration Opportunities

Generally, transmission and distribution system losses increase as the distance between generation and customer load increases. When renewable energy is located in the distribution system close to customers, it can reduce losses.[119] To take full advantage of increasing renewable resources in the distribution system, state PUCs are working with utilities to better understand how distributed renewables can be managed and integrated into the system. Improved voltage and reactive power management, together with the aid of modern inverters and complementary deployment of demand response and storage assets, show promise for helping maximize the clean energy contribution of renewable resources.

- *Improved voltage and reactive power management with modern inverters.* Utilities and state PUCs are increasingly looking to strategies like improved voltage monitoring and management in anticipation of more distributed renewables coming online. The greatest effects will likely be felt in distribution feeders—the final stage in the delivery of electric power to individual consumers. Traditionally, these feeders were designed for one-way power flow—from substation to customer. Similar to the branches of a tree, feeders have their heaviest loading near the substation with decreased loading as the various branches reach their ends. Generally, the voltage on distribution feeders also falls at points farther from the substation. Utilities have traditionally managed these voltage drops using conventional technology. Adding distributed generation on longer circuits can boost voltage to help reach end-of-line customers, but the distribution system must still stay within acceptable voltage levels.

  Combined with other modern grid technologies, advanced inverter systems used with solar and wind generation have the potential to further benefit the system by improving control of feeder voltages. In general, it is advantageous to locate solar generation near substations because electricity generally flows from generation to load. However, voltage also tends to be higher closer to substations, and under some grid conditions, conventional inverters disconnect solar resources to avoid overvoltage to the system. Advanced inverter systems have the potential to tailor the output of solar and wind resources to meet system needs and provide grid services such as voltage or reactive power support and can respond very quickly when needed. Many of the inverters being installed in the United States today have smart capabilities that are not yet in use. Government and industry are working to develop standards for how advanced inverters will work in the U.S. market (Solar Oregon 2014).

- *Complementary deployment of demand response and storage.* Since demand is variable and not completely predictable or controllable, grid system operators typically rely on conventional fossil-fuel-fired peaking power plants to balance generation and demand. This balancing happens on time scales from seconds to hours. Since some renewable generation is intermittent, as the amount of renewable generation is increased, balancing becomes more challenging. Adding flexible loads through demand response and storage has the potential to help system operators balance supply and demand without the need to start up economically inefficient power plants for short periods solely to provide additional balancing capability.

[119] This advantage applies to all distributed generation, not just renewable energy generation.

Traditional demand response programs, which are offered by many utilities nationwide, provide financial incentives in return for customers reducing consumption during certain conditions, e.g., periods of peak load. Historically, most utilities call on these customers to respond to peak events for a limited number of hours per year. Automation of demand response offers great promise for customer participation, not only in peak load reduction events but also in serving as a flexible resource to provide other grid services for shorter periods of time. Utilities have begun conducting pilot programs to automate demand response by communicating with the building energy management systems of participating commercial customers. The emergence of ENERGY STAR products with connected functionality (see text box), combined with automation, may increase the willingness and ability of residential customers to participate in demand response initiatives.

ENERGY STAR® Products with Connected Functionality

To help advance the market for products with connected functionality that can offer immediate consumer convenience and control as well as energy and demand savings, EPA has developed connected criteria for several appliance categories as well as pool pumps. ENERGY STAR products with connected functionality offer:

- Convenience: communicate with other devices and services, provide alerts and maintenance information.
- Personalized insights: provide energy usage feedback.
- Energy and cost savings: provide a means of optimizing energy use to enable savings.
- Control: remotely control energy settings either through a consumer or utility device.

By recognizing ENERGY STAR-certified products with connected functionality, EPA hopes to encourage manufacturers to design products that offer consumer convenience and control and ultimately help customers manage their energy usage directly or enable their participation in utility demand response programs.

In addition, storage is being used to support renewable energy integration. For example, storage can be used to store excess renewable energy for later use; it can be installed close to where energy will be consumed, potentially alleviating congestion on transmission and distribution systems during peak periods; and certain storage technologies with rapid response capabilities can be used to help manage fluctuations on the electricity grid caused by the intermittency of some renewable energy resources. Due to their flexibility and ability for rapid response, automated demand response and storage are being explored by system operators for better integrating distributed renewable energy resources.

States with Policies to Encourage Energy Efficiency and Renewables Integration in Grid Investments

As noted in previous sections, efforts to ensure that modern grid investments include energy efficiency and support the growth in renewable resources are not captured neatly by any single policy mechanism. Therefore comprehensive data on the extent of these efforts are not widely available. Nonetheless, there have been a few notable efforts in California, Massachusetts, and Hawaii to convene multiple stakeholders to address diverse perspectives including environmental considerations in planning grid modernization efforts (see *State/Regional Examples* for additional information).

A growing number of states have gained experience with modern grid deployments in part due to the American Recovery and Reinvestment Act of 2009, Smart Grid Investment Grants. Overseen by the U.S. Department of Energy (DOE), Smart Grid Investment Grant matching funds totaling $3.4 billion were awarded to nearly 100 recipients to accelerate the modernization of the nation's electricity infrastructure. As a result, a growing number of states, PUCs, and utilities have gained operational experience with enabling technologies and related enhanced operations. In addition, since award recipients were required to co-fund projects, many states and utilities have gained experience with funding grid modernization efforts (See Table 7.5.1). States are also gaining knowledge and operational experience by supporting microgrid projects at state universities or critical facilities. (See text box, "Campus Microgrids Serve as Laboratories of Learning.")

Table 7.5.1: States with Policies to Advance Energy Efficiency and Renewable Integration in Grid Investments

Policy	Description	States
Stakeholder process for grid modernization	Has convened or initiated a stakeholder process to determine how to plan for and implement modern grid investments.	CA, HI, IL, MA, NY, VT
Pilot for voltage management to improve energy efficiency	At least one utility in the state has implemented pilot effort testing the ability of modern grid investments to better manage voltage with the explicit goal of achieving energy efficiency benefits.	AZ, CA, CO, IL, NV, OH, RI, WA
Credit for voltage management for energy efficiency as a resource	Has policies or plans to enable utilities to count energy efficiency from improved voltage management toward energy efficiency goals or resource standards	Pacific NW (ID, parts of MT, OR, UT, WA, WY), AZ, IN, MD, NC, PA
Decision about cost recovery for grid investments that deliver end-use energy efficiency benefits	Has made an initial decision on cost-recovery for grid-side investments that deliver end-use energy efficiency benefits. This does not include compensating for lost revenue associated with reduced sales. Maryland however does have revenue decoupling (see Section 7.2 for more on this topic).	Recovery through rates: MD Recovery through other mechanism: IN, Pacific NW (WA, OR, ID, parts of MT, WY, UT)
Policy on customer access to energy usage data	Has policies supporting customer access to their own energy usage data.	CA, CO, IL, OK, PA, TX, WA

A few states are planning for and crediting grid-side efficiency in their energy efficiency goals. The Northwest Power and Conservation Council—which coordinates supply planning for the Columbia River basin and serves Washington, Oregon, Idaho, and parts of Montana, Wyoming, and Utah—targets distribution energy efficiency in its most recent power plan. Arizona, Maryland, North Carolina, and Pennsylvania have also approved voltage management for energy efficiency and will allow it to count toward their energy efficiency goals.

Big data is also presenting opportunities for utilities to enable greater energy efficiency. As utilities explore how to capture, store, analyze and take advantage of big data, state regulators are grappling with issues of data access and privacy. Several states including California, Colorado, Illinois, Oklahoma, Pennsylvania, Texas, and Washington have policies giving customers access to their own data, though application of this principle to support greater energy efficiency varies (SEE Action 2012). In addition, utilities and third parties can voluntarily adopt DOE's Voluntary Code of Conduct, which includes concepts and principles regarding customer data privacy.[120]

States also are encouraging utilities to increase customer access to energy usage data through mechanisms such as Green Button and Web services to exchange data with Portfolio Manager, EPA's ENERGY STAR building benchmarking tool. Regardless of the mechanism used, states must also balance customer privacy with ease of data access (SEE Action 2013). States are beginning to explore use of demand response to assist with grid operation and the integration of renewables. Currently, at least one utility in every state offers some form of

[120] DOE's Office of Electricity Delivery and Energy Reliability and the Federal Smart Grid Task Force facilitated a multi-stakeholder process to develop the Code. The Final Concepts and Principles, as released on January 12, 2015, are available at http://www.energy.gov/sites/prod/files/2015/01/f19/VCC%20Concepts%20and%20Principles%202015_01_08%20FINAL.pdf.

demand response through load management programs and/or pricing programs. Even though demand response is being offered across the country, automation of demand response to provide additional grid services and support the integration of renewable energy is not yet widespread. For example, the California Energy Commission is exploring policies to expand the amount of automated demand response resources for renewable energy integration (CEC 2013).

Similarly, states are enacting policies and regulations to encourage the demonstration and deployment of storage to complement the integration of greater renewable energy in a modern grid. For example, California has mandated 1.3 gigawatts of storage statewide by 2024 and requires future renewable portfolio standards plans in the state to comply with the storage decision (CPUC 2014a). Washington State enacted two laws related to energy storage: the first enables qualifying utilities to credit energy storage output of renewable sourced energy at 2.5 times the normal value in meeting the state's renewable energy targets, and the second requires electric utilities to include energy storage in all integrated resource plans (Washington House of Representatives 2013a, 2013b). Lastly, the New York Battery and Energy Storage Technology Consortium is an example of leveraging a public-private partnership to research storage technology and manufacturing and aid energy storage organizations and other stakeholders on policies and programs that could improve energy storage.

Campus Microgrids Serve as Laboratories of Learning

"Microgrid" refers to a group of interconnected distributed generators (such as solar panels and diesel generators), storage, combined heat and power (CHP) systems, distribution lines, controllable loads, and associated communication and control systems. A microgrid can be designed to meet some or all of the power needs of a facility or campus and may or may not be connected to the larger electric grid. When connected to the grid, a microgrid can be designed to island itself during a power outage to serve all or part of the load of the facility or campus. A grid-connected microgrid can also be designed and managed to serve as a multi-function grid resource, providing reliable and resilient electricity supply, load shedding, and other important grid services. To date, most microgrids have been developed for critical applications, such as military installations, and for university campuses, where they also serve as laboratories of learning. For example,

- The University of California, San Diego (UCSD) operates a microgrid that generates roughly 95 percent of its own energy and saves more than $8 million annually compared to importing the same amount of energy. UCSD leveraged various state energy efficiency and clean energy programs, federal grants, the university's capital investment budget and other sources to fund their microgrid build out. UCSD's microgrid consists of a CHP system; solar power; a fuel cell; battery energy storage systems; and flexible loads including a thermal energy storage tank, electric and steam driven chillers, and building level demand response. The performance of all of the systems is recorded using a centralized monitoring system, giving UCSD access to key data points that can help to continually improve the operation of the microgrid. The UCSD microgrid serves as a testbed for campus research including research on how to utilize its microgrid to provide renewable integration services. (See http://calsolarresearch.ca.gov/funded-projects/73-innovative-business-models-rates-and-incentives-that-promote-integration-of-high-penetration-pv-with-real-time-management-of-customer-sited-distribut and http://sustainability.ucsd.edu/highlights/microgrids.html).
- In addition to providing economic benefits and the potential to supporting clean energy integration, microgrids are getting increased attention for their ability to island from the grid during severe weather events or other electricity service disruptions. Princeton University gained national recognition for the successful performance of its microgrid in the wake of Hurricane Sandy. The campus has a gas turbine generator and nearby solar field capable of producing 15 megawatts. After the hurricane, Public Service Enterprise Group restored energy to the campus long enough for Princeton to restart its generator before the utility grid went out again. The campus was able to serve as a staging ground for firefighters, paramedics, and emergency service workers for a day and half until the larger electric grid was restored to service (Princeton University 2014).

Designing Effective Policies

A number of key issues have emerged from state and PUC efforts to advance grid modernization, including 1) who participates and in what aspects of the grid modernization dialogue; 2) key considerations such as what needs to be considered in design, how to gain operational experience operating a modern grid, and how to fund and make the business case for investments; and 3) how to balance ratepayer costs and benefits.

Participants

- *State executive and legislative bodies.* At the state level, the governor's office, state legislature, and state energy offices are often involved in policy- and goal-setting that includes or is facilitated by modern grid investments. Depending on how utilities are regulated in a given state and the issue at hand, state legislatures may become involved in modifying existing legislation to accommodate modern grid investments. For example, state energy efficiency resource standard legislation may be created or revised to include grid-side efficiency investments.
- *PUCs/utility boards.* PUCs and utility boards of municipal or cooperative utilities oversee goals, investments, and ratemaking for electric utilities. Most of this oversight is found in specific regulatory proceedings, including those for modern grid investments. These proceedings range from those that approve pilot efforts to those that define what resources count toward energy efficiency resource standards, determine AMI investment, or modify rate structures. For investor-owned utilities, PUCs also deliberate on a range of topics—such as transmission and distribution capital plans and planning standards—through periodic general rate case proceedings. PUCs and utility boards are faced with new challenges as the volume and complexity of proceedings increase.
- *Electric utilities.* Electric utilities are the primary purchaser of modern grid technologies and need to make the internal and external business case for modern grid investments while also responding to commission mandates or board directives. In the changing landscape of modern grid technologies and operations, utilities are often concerned about investing in technologies that may become obsolete before their costs can be fully recovered and about being compensated between rate cases for lost revenues associated with reduced electricity use due to grid-side energy efficiency or increased customer reliance on distributed generation (including renewables). (See Section 7.2.) While utilities have the expertise to execute grid modernization initiatives, absent permission or guidance from their regulators, their tendency may be to avoid risk or delay deployment.
- *Regional transmission organizations (RTOs)/independent system operators (ISOs).* About 60 percent of U.S. electric power supply is managed by RTOs or ISOs: independent, membership-based organizations that ensure reliability and usually manage the regional electric supply market for wholesale electric power. In the rest of the country, electricity systems are operated by individual utilities or utility holding companies (EIA 2011). RTOs/ISOs engage in long-term planning that involves identifying effective, cost-efficient ways to ensure grid reliability and system-wide benefits. Coordination and cooperation between utilities, state PUCs, and RTOs/ISOs is often required to advance energy efficiency and renewable energy integration goals in grid modernization efforts.
- *Public interest organizations.* Groups representing consumers, environmental interests, and other public interests are often involved in offering technical expertise as well as public perspectives. Consumer advocates are often concerned with maintaining low rates and ensuring equitable treatment of all customer classes. Environmental advocates are often concerned with ensuring that all cost-effective energy efficiency is considered and that robust funding for traditional energy efficiency programming is maintained; in some areas they may also advocate for transmission and distribution investments to

support renewables' integration. Increasingly, public interest organizations are interested in privacy and data access issues associated with AMI as well as in ensuring that utility business models are increasingly aligned with public interest goals.

- *Vendors and service providers*. Vendors of smart grid technologies and software may be called on to provide expertise during public proceedings, to respond to formal requests for information or proposals from utilities or states, or to participate directly in public dialogue to advance the interests of their organization. Service providers including those that work to acquire and aggregate demand response and distributed solar resources may be interested in regulatory proceedings that will affect how distributed resources will be valued and compensated by regulators, utilities, and capacity markets. Other service providers, such as those wishing to offer integrated home energy management services, may be interested in data access and privacy issues.
- *Customer/general public.* Customer engagement will vary by customer size and class and/or interest in key issues such as rate impacts and pricing structures, power quality, ability to participate in providing demand response and other grid services, interest in renewable energy, and data access and privacy. In general, it is advisable to provide customers with proactive education and outreach on the installation of AMI meters and any changes to billing or rate structures.

Key Design Considerations

Many existing policies affecting electricity generation, transmission and distribution, renewable energy, and demand-side management (e.g., energy efficiency and demand response) have been designed independently from one another and as a result are often planned and managed by different departments within a utility—each with unique expertise and regulatory drivers. Successful planning and management of modern grid investments to achieve broader energy efficiency and renewable energy benefits requires consideration of how to better integrate utility functions and policy goals to achieve the multiple objectives of grid modernization. Key considerations during the design of state or PUC policies for modern grid investments include:

- The prudent level of investment given the state of the market, considering local conditions and system needs, existing investments, the availability of external funding (e.g., federal grants), and experience with key technologies.
- How the need to engage multiple functional departments within a utility will affect timing and success.
- The best way to gain operational experience using modern grid technology to maximize energy efficiency benefits and distributed resource integration.
- When, where, and how to take proven pilot initiatives to scale.
- How to apportion costs, given the multiple benefits of these technologies and practices.
- How to balance customer rates and utility revenue requirements.

The following section provides more information on these key policy design considerations.

Evaluating current systems and future needs

Before making investment decisions, representatives from multiple departments within a utility meet to discuss existing system assets and operations, anticipated future system needs, the purpose of planned pilots, and key design considerations moving forward (see *Program Implementation and Evaluation* later in this section). During this phase, participants review technical data about the system such as the configuration of the distribution system and substations; equipment ratings; historical data on usage, voltage, costs, reliability, and risk; and current operating criteria and practices such as how temperature is monitored and controlled at the transformer to avoid overheating and extend equipment life. State and Federal regulatory requirements also are discussed to ensure a clear understanding of what various parties are legally required to do and identify any regulatory issues, such as how property rights for new assets will be assigned, that will require further legal review or action. PUCs are not normally involved at this stage but can have influence whether such evaluation occurs by calling for an assessment of grid side energy efficiency potential or requesting utilities in their jurisdiction consider pilot efforts to deliver grid side efficiency or improve the integration of distributed renewables.

Gaining operational experience

Most utilities conduct pilot initiatives to gain experience with new technologies and new operational practices before larger-scale investment. A significant number of utilities have already gained some operational experience with one or more modern grid investments through participation in Federal Smart Grid Investment Grants and Demonstration Programs, as well as through demonstration projects in partnership with the Electric Power Research Institute (see *Interaction with Federal Programs* and *Information Resources*, respectively). Pilots and demonstration projects may be subject to PUC or board approval. During pilots it is helpful to establish clear milestones and a process for reviewing progress against them, and to track actual costs and benefits and compare them to expectations. With proven costs and benefits from a real world pilot, the business case for full deployment gains credibility for approvals within utilities and with regulatory bodies.

Making the business case

When evaluating the benefits of investing in modern grid technologies and related changes to operations and management, states, PUCs, and utilities have found it helpful to apply a comprehensive benefit-cost analysis that accounts for the risk associated with some of these investments. The Bonneville Power Administration (BPA) recently conducted an interim analysis of the smart grid regional business case for the Pacific Northwest (BPA n.d.) that accounted for the range of uncertainty and evaluated investments based on energy efficiency benefits, reliability benefits, and improved operational efficiency. Importantly, their assessment took into account only the net benefits and costs from adding modern or smart grid capabilities compared to the benefits and costs of traditional technologies/approaches. Their interim assessment found that benefits significantly outweighed costs for modern grid investment and management strategies targeted to improving grid reliability, optimizing voltage and reactive power to achieve energy efficiency, and automating demand response to enable customers to respond to signals provided through the electricity supply chain (BPA n.d.).

Note that costs and benefits will vary by location and specific operating situations. The same technology can have a very different implementation cost in a rural area with low customer density than in an urban area with high customer density and significant commercial loads. Service territories need to be broken down into similar groupings of circuits, which can then be separately analyzed in terms of costs and benefits. In addition, modern grid investments often interact with one another, and that needs to be taken into account. Often investment in one technology helps avoid costs in the implementation of another technology. On the benefits side, care needs to be taken to avoid double-counting benefits, particularly when multiple technologies are being considered. In addition, it is often challenging to value the services technologies will enable when they do not yet exist across the population.

Funding and cost recovery

Modernizing the electric grid requires an investment of time, money, and human capital. Some believe that, in the long run, a rethinking of the utility business model is needed so that utilities no longer recover fixed operating costs based on the volume of electricity they deliver to customers or receive compensation based on capital investments they make to provide service but for the broader services they provide to customers and society. In most parts of the country, utilities are years away from experiencing significant revenue impacts from the high penetration of distributed renewables or grid-controlled energy efficiency, but a few states with higher renewables penetration and/or a strong interest in improving grid resiliency to respond to increasing severe weather events have begun to discuss an evolving utility business model as part of a larger conversation about grid modernization (see *State/Regional Examples*).

In the near term, utilities and their regulators are evaluating how to fund modern grid investments, absent a full rate case, since transmission and distribution planning investments are typically recovered through rates (see Section 7.1) and access to capital has been cited as a key barrier by some utilities (NEEA 2014). Additional or unforeseen investments in grid technology require utilities to risk that these investments will not be recovered through future rate cases. Other issues include ensuring that benefits are widely distributed among customers and whether regulators will compensate utilities for lost revenues when the modern grid investment delivers energy efficiency benefits to customers. A growing number of utilities receive compensation for revenue lost from reduced sales attributable to their energy efficiency programs (see Section 7.2).

Interaction with Federal Programs

Several federal-level programs and efforts are targeted toward fostering grid modernization. Combined, the Smart Grid Investment Grant and the Smart Grid Demonstration Program (authorized by the Energy Independence and Security Act [EISA] of 2007 and amended through the Recovery Act) authorized $5 billion to accelerate grid modernization activities across the country. Smart Grid Investment Grant projects spanned AMI, customer systems, distribution system upgrades, transmission upgrades, equipment manufacturing, and cross-cutting systems. Smart Grid Demonstration Program projects focused on verifying the viability, costs, and benefits of regional smart grid demonstrations and on projects demonstrating the use of energy storage systems to provide grid services and renewable resource integration.[121] These funding sources were in addition to the direct project funding from the U.S. Department of Agriculture's Rural Utility Service for rural electricity delivery infrastructure. The EISA also called on the National Institute of Standards and Technology to coordinate the development of a framework that includes protocols and model standards for information management so that smart grid devices and systems work together. The resulting Smart Grid Interoperability Panel work is now administered through a public-private partnership (see http://www.sgip.org).

Because of the diversity of technologies and applications that fall under the umbrella of grid modernization, there are several other agency efforts and programs that support different aspects of grid modernization as co-benefits of their primary work, such as energy efficiency, economic development, security, and consumer protection. The Federal Smart Grid Task Force,[122] established under Title XIII of the EISA and led by DOE's Office of Electricity Delivery and Energy Reliability, is designed to ensure awareness, coordination, and integration of the diverse activities of the federal government related to smart grid technologies, practices, and services across federal agencies. Given the nexus between smart grid and the need for rapid data

[121] For information on Smart Grid Demonstration Program projects, see http://www.smartgrid.gov/recovery_act/overview/smart_grid_demonstration_program.

[122] For more information on the Federal Smart Grid Task Force, see https://www.smartgrid.gov/task_force.

communications, the U.S. Department of Commerce, National Telecommunications and Infrastructure Administration's Broadband Technology Opportunities Program (funded through the Recovery Act), has also resulted in partnerships between broadband providers, electric cooperatives, and communities that would otherwise be underserved by broadband deployments.

Interaction with State Policies

Modern grid investments can enable or facilitate a range of state policies focused on reducing costs, improving the environment, promoting innovation, and enhancing reliability. However, some of the policies do not provide the appropriate mechanisms or incentives to capture all of the available capabilities and benefits. As modern grid applications continue to emerge, states are reviewing policies to determine how to take better advantage of the additional capability of the modern grid.

For example, investments that can reduce customer energy use (such as CVR) do not typically count toward a utility's energy efficiency resource standard or similar goals. Other policies that encourage more renewable generation, such as renewable portfolio standards (see Chapter 5), may be facilitated by increased flexible loads and advanced demand response if implemented in a coordinated way. Similarly, customer information programs that use AMI data may improve energy efficiency deployment and encourage energy-saving behaviors. However, many utilities that provide such information programs to customers are not evaluating, measuring, and verifying energy savings.

Program Implementation and Evaluation

Implementation

Within a utility, senior leadership as well as multiple operating units within the company are often involved in deploying, managing, monitoring, and measuring programs or initiatives that leverage grid modernization investments for load reduction or energy efficiency. Utilities have cited establishing coordination across departments as a key step for success. It is helpful for states and their PUCs to understand these operational complexities in setting realistic timeframes for pilot efforts or larger-scale deployment. The following are examples of how different operating departments within a utility may be engaged in modern grid deployments or pilot initiatives:

- Electric distribution operations staff are directly engaged in planning and operations. They know critical system data; understand the mix of residential, commercial, and industrial customers along various feeders; and are responsible for ensuring that grid operations deliver expected services within allowable voltage levels.
- Electric forecasting departments are instrumental in understanding and planning future load requirements, including specific seasonal, peak, time-of-day, or customer class impacts.
- Energy efficiency and demand-side management program staff are interested in the implications of grid-side efficiency programs and the potential to count customer impacts toward program goals. As such, they provide valuable insights on how to track and monitor costs and benefits.
- Key account managers are usually incorporated into any demonstration that could affect service to large customers or customer groups.
- Customer call centers and billing departments manage customer contact, usage history, and other information necessary for pilot design and measurement, depending on the project being implemented.

They are also often a first point of contact for any service or billing accuracy complaints, such as those associated with new AMI meter deployments.

- Regulatory and public affairs staff become involved in developing the strategy for raising awareness of new technologies among customers, making the business case for implementing modern grid investments for energy efficiency and peak load reduction, and engaging in related regulatory proceedings.

Oversight

The primary oversight of utility distribution modernization efforts is the state PUC or utility board, depending on utility type. These entities generally approve capital investments, establish the policies that govern investment and operation of the electric grid, and ensure fair treatment and equity between the ratepayer and the utility and among ratepayers.

Decision-makers generally have both formal and informal options available for oversight. For example, formal PUC processes are often handled through dockets with evidence-based hearings and opportunities for public comment.[123] These formal processes are generally used to approve or disapprove a specific grid investment proposal. For a deeper exploration of the pros and cons of a range of grid modernization options, oversight organizations—on their own or at the request of interested parties—may opt to initiate an informal process, such as workshop or stakeholder collaboration. Informal processes may lead to formal processes, but in the meantime they allow decision-makers to engage and learn without the limitations associated with rules of evidence, enabling a deeper exploration of the pros and cons of the full range of opportunities.

Evaluation

Some states are requiring utilities to evaluate the benefits of modern grid deployments similarly to other energy efficiency, renewable energy, and CHP initiatives, as illustrated below using CVR as an example.

- *Understanding potential.* As discussed previously, the potential of voltage management to deliver energy efficiency to customers will vary by circuit; it is best informed by breaking service territories down into groups of circuits similar in length, current voltage levels, customer class, and other technical characteristics. Utilities often conduct modeling to inform which circuits are best suited to voltage management. Once operational experience is gained on a mixture of circuits, utilities can understand and target high-value circuits for future deployments.
- *Developing tracking metrics and systems*. All evaluations benefit from developing tracking metrics and systems in advance of deployment. These need to be informed by a clear understanding of the multiple objectives of a deployment.
- *Establishing baselines.* As with other energy efficiency investments, establishing credible baselines is critical to claiming program impacts. In the case of CVR, since customer energy use naturally depends on weather and season, it is common to cycle voltage control on and off for a sufficient duration at different times throughout the year. Depending on system type, utilities usually follow either a day on/day off or week on/week off protocol. Because data gained from these operations are often used as proxy data for other system-wide planning efforts, it is important that they be regularly refreshed. For example, if a particular circuit experiences rapid load growth, the usefulness of its data for broader estimation purposes will quickly be reduced.

[123] See Section 7.1, "Electricity Resource Planning and Procurement," for more information on formal processes PUCs use to approve utility investments.

- *Assessing benefits and costs.* As discussed previously, it can be beneficial to understand the additional costs and the additional benefits that can be realized from implementation using modern grid technology versus traditional approaches. For example, CVR can be implemented with conventional grid technology, however additional energy savings could be realized from modern grid technologies. It is also important to take into account difficult-to-quantify benefits such as increased operational confidence that come from modern grid investments.
- *Understanding how benefits are allocated.* In a modernizing grid, customers are increasingly able to both consume and generate electricity, can both benefit from and provide grid services, and can participate knowingly or passively in energy efficiency or demand response programming. As a result, utilities and regulators are increasingly interested in tracking costs and understanding benefits at a more granular level. Depending on the policy and regulatory environment, the distribution of impacts can vary—either between ratepayers and the utility or among different ratepayer groups. The use of multiple methods can help establish these distributional impacts. For example, comparing CVR impacts at the substation to CVR impacts at the customer meter combined with engineering simulations are useful for estimating the proportion of energy savings the customer will realize (compared to the energy savings the utility will realize from operational improvements).

For utilities interested in gaining energy efficiency credit for grid-side efficiency programming, use of a third-party evaluator will be beneficial—and in many cases required for making the case to their oversight authority. Many states require use of third-party evaluators for energy efficiency program impact evaluations.

State and Regional Examples

Massachusetts

In October 2012, the Massachusetts Department of Public Utilities began an investigation into what a grid modernization initiative should look like (Massachusetts Department of Public Utilities 2014a). A working group was established to gather input from various grid-facing and customer-facing stakeholders and make recommendations. After further deliberation and review, the Department issued an Order in June 2014 requiring all of the state's utilities to develop and submit 10-year grid modernization plans designed to 1) minimize outages and 2) reduce system and customer costs through optimizing demand, facilitating integration and higher penetration of distributed resources, and improving management of assets and personnel (Massachusetts Department of Public Utilities 2014b). Utilities were also required to submit 5-year capital investment plans in support of these goals. In a separate but related order, the commission requested that utilities establish time-varying rates as their default rates (Massachusetts Department of Public Utilities 2014c).

California

California was an early innovator in grid modernization, with the California Public Utilities Commission (CPUC) producing its first grid modernization plan in 2010 (CPUC 2014b). Utilities are now required to submit annual Smart Grid Deployment Plan updates to CPUC, and CPUC in turn produces an annual Smart Grid Report for the Governor and legislature detailing annual progress. California has become one of the first states to achieve near complete coverage of AMI across all its utility service areas, and CPUC has put forth several measures to address the questions of data access and consumer privacy that AMI brings to the forefront (CPUC 2014c). The California Energy Commission is also exploring policies to expand the amount of automated demand response resources for renewable energy integration (CEC 2013). California, along with other states in the Western Electricity Coordinating Council, has initiated a program to deploy technologies that help operators better integrate renewables through monitoring grid conditions and receiving real-time automated alerts (California ISO 2011).

Maryland

As part of its order transitioning into the next 3-year phase of the Empower MD Energy Efficiency Act of 2008, the Maryland Public Service Commission, “intrigued by the opportunities for highly cost-effective savings that CVR programs could create,” approved one proposed utility CVR program and directed all other regulated companies to develop or accelerate CVR programs. In the same order, the Commission requested that utilities recover the costs of their CVR programs in rates rather than through the Empower Maryland Surcharge, allowed the companies to count their projected energy savings generated by their respective CVR programs toward their EmPOWER energy efficiency goals, and requested companies to track and separately report the costs of their CVR programs to determine cost-effectiveness (MD PSC 2011).

Indiana

In Indiana, the legislature created a new tracker, which is overseen by the Indiana Utility Regulatory Commission, to encourage utility investment in transmission, distribution and storage system improvements. Traditionally, these costs would have been included in rates for recovery in a base rate case. The tracker enables utilities to recover these costs on a more regular basis. Before costs can be passed through to consumers, the utility is required to submit a 7-year plan that is subject to public comment and approval by the Indiana Utility Regulatory Commission. The utility is also required to undergo a rate case in that 7-year period (Indiana General Assembly 2013).

Pacific Northwest

The Northwest Power and Conservation Council, in its Sixth Conservation and Electric Supply Plan, targets 400 average megawatts of savings from utility distribution systems by 2029. As a wholesale electric power marketer and transmission operator in the Northwest, BPA contributes to achieving the goals set forth in the plan. Through its Energy Smart Utility Efficiency Program, BPA offers incentives of $0.25 per kilowatt-hour to acquire utility distribution sector energy savings including voltage optimization and high-efficiency transformers (BPA 2012, 2014; NPCC 2010).

What States Can Do

States and their PUCs interested in advancing grid modernization efforts to achieve energy efficiency benefits and anticipate the need to better accommodate growing renewable resources may wish to consider the following actions:

- *Conduct pilot-scale efforts*. Pilot studies can help utilities gain operational knowledge and an understanding of costs and benefits prior to broader implementation and can inform energy efficiency, CHP, and distributed renewables potential.
- *Assess energy efficiency potential.* Grid-side energy efficiency has not historically been included in energy efficiency potential studies. States can consider including grid-side efficiency deployments such as CVR in existing potential studies or as a separate effort.
- *Integrate in resource/procurement planning.* Modern grid investments can increase operational confidence in grid-side energy efficiency, demand-responsive resources, and the ability of the distribution system to integrate and benefit from distributed generation resources such as CHP and renewable energy. As such,

these resources deserve increased attention in long-term integrated resource and procurement planning efforts.

- *Review policies to encourage investment:* Particularly for states that have already gained operational knowledge with modern grid deployments, review of the role of existing utility policies in inhibiting or encouraging investment in modern grid technologies can be beneficial to encouraging larger scale deployment. For example, utilities have expressed that crediting customer energy efficiency benefits from CVR as part of their energy efficiency resource standards as an important incentive to moving forward with deployments. Similarly, utilities that have decoupling policies in effect are neutral to the revenue losses from reduced sales associated with both CVR and customer-sided renewables. (See Section 7.2.)
- *Convene a stakeholder process.* Understanding the perspectives of multiple stakeholders will become increasingly important as grid modernization efforts mature and distributed resources become more prevalent. States may benefit from tracking the proceedings of leading states to understand emerging issues.

Information Resources

Federal Resources

Title/Description	URL Address
A Policy Framework for the 21st Century Grid: A Progress Report. This 2013 report summarizes recent federal government actions to encourage the development of a 21st century grid.	http://www.whitehouse.gov/sites/default/files/microsites/ostp/2013_nstc_grid.pdf
SmartGrid.gov. SmartGrid.gov is the gateway to information on federal initiatives that support the development of technologies, policies, and projects to transform the electric power industry.	http://www.smartgrid.gov
Smart Grid Investment Grants and Smart Grid Regional and Energy Storage Demonstration Projects. These two Web pages provide information on American Reinvestment and Recovery Act grant-funded grid modernization and energy storage demonstration projects across the United States. The projects were awarded from DOE's Office of Electricity Delivery and Energy Reliability.	http://energy.gov/oe/technology-development/smart-grid/recovery-act-smart-grid-investment-grants (investment grants) http://energy.gov/oe/services/technology-development/smart-grid/recovery-act-sgdp (demonstration projects)
Federal Energy Regulatory Commission (FERC). FERC's website provides information on smart grid advancements, including annual assessments of demand response and advanced metering potential.	http://www.ferc.gov/industries/electric/indus-act/smart-grid.asp http://www.ferc.gov/legal/staff-reports/2014/demand-response.pdf
National Forum on Demand Response. The U.S. Department of Energy and the Federal Energy Regulatory Commission sponsored a forum as part of the Implementation Proposal for the National Action Plan for Demand Response. In February 2013, National Forum working groups published a series of reports on cost-effectiveness, measurement and verification, program design and implementation, and tools and methods.	http://energy.gov/oe/services/electricity-policy-coordination-and-implementation/state-and-regional-policy-assistanc-7
USDA Rural Utility Service Loans. USDA loans funds to rural electric utilities for a variety of infrastructure expansions and improvements, including modern grid technologies.	http://www.rurdev.usda.gov/Home.html
Broadband USA. This Web page provides information on American Reinvestment and Recovery Act grant-funded community broadband projects, many of which include smart grid capabilities. The projects were awarded from the U.S. Department of Commerce, National Telecommunications and Infrastructure Administration.	http://www2.ntia.doc.gov/about
State and Local Energy Efficiency Action Network (SEE Action). The federally facilitated SEE Action summarizes information on the importance of customer access to energy use data as a tool for supporting energy efficiency in the residential and commercial sectors, and provides related resources for state and local policy makers and their partners.	https://www4.eere.energy.gov/seeaction/topic-category/energy-use-data-access
National Institute of Standards and Technology (NIST). NIST's website provides an overview of smart grid technology and the development of interoperability standards to make it possible.	http://www.nist.gov/smartgrid/

Title/Description	URL Address
Smart Grid Legislative and Regulatory Policies and Case Studies. This 2011 report highlights the development of the smart grid in the United States and abroad, summarizes U.S. smart grid legislation and regulation, and provides case studies of smart grid pilots and programs in the United States.	http://www.eia.gov/analysis/studies/electricity/
Data Privacy and the Smart Grid: A Voluntary Code of Conduct. Utilities and third parties can voluntary adopt these concepts and principles in order to address privacy related to customer data.	http://www.energy.gov/sites/prod/files/2015/01/f19/VCC%20Concepts%20and%20Principles%202015_01_08%20FINAL.pdf
Grid Energy Storage. This 2013 report describes potential options to improve energy storage, as well as specific actions that could help maintain scientific advancements and a pipeline of project deployments.	http://energy.gov/oe/downloads/grid-energy-storage-december-2013
Integrated Building Energy Systems Design Considering Storage Technologies. This 2009 report analyzes how energy storage technologies can help with the optimization of micro-generation systems. It features examples from New York and California.	http://emp.lbl.gov/sites/all/files/REPORT%20lbnl-1752e_0.pdf

Potential and Business Case

Title/Description	URL Address
Evaluation of Conservation Voltage Reduction (CVR) on a National Level. This 2010 report presents an estimate of the benefits of CVR for individual feeder types, as well as an extrapolation of the benefits on a national level.	http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19596.pdf
BPA Study of Smart Grid Economics Identifies Attractive Opportunities and Key Uncertainties. This primer summarizes a white paper documenting the interim results of an economic assessment for smart grid technologies in the Pacific Northwest.	http://www.bpa.gov/Projects/Initiatives/SmartGrid/DocumentsSmartGrid/BPA-Smart-Grid-Regional-Business-Case-Summary-White-Paper.pdf
Estimating the Costs and Benefits of the Smart Grid. This 2011 technical report, a partial update of an earlier report, documents the methodology, key assumptions, and results of a preliminary quantitative estimate of the investment needed to create a viable smart grid.	http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001022519
Costs and Benefits of Conservation Voltage Reduction: CVR Warrants Careful Examination. This 2013 report investigates the CVR deployment experience at four rural electrical cooperative utilities and uses their data to develop and calibrate a hybrid power flow-economic model, which is used to derive a cost-benefit analysis methodology for CVR.	https://smartgrid.gov/sites/default/files/doc/files/NRECA_TPR2_Costs_Benefits_of_CVR_0.pdf
Market Analysis of Emerging Electric Energy Storage Systems. This research paper evaluates the economics of two emerging electric energy storage systems: sodium sulfur batteries and flywheels.	http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/DOE-NETL-2008-1330-MarkAnalyElectEnergyStorageSys-FinalRpt.pdf

Stakeholder Processes

Title/Description	URL Address
Illinois Energy Infrastructure Modernization Act of 2011. Provides Illinois Investor Owned Utility plans to make significant upgrades and investments to the electric grid while meeting performance metrics. Stakeholder groups engaged to ensure that related consumer and environmental benefits, including greenhouse gas benefits, are to be tracked and reported for these investments.	http://www.icc.illinois.gov/electricity/infrastructureinvestmentplans.aspx
Smart Grid Roadmaps. This series lays out a path and technical vision for the discovery and deployment of smart grid technologies. It includes links to current and past stakeholder processes.	http://www.caiso.com/informed/Pages/CleanGrid/SmartGridRoadmap.aspx
Report to the Governor and the Legislature: California Smart Grid—2012. This report, published in May 2013, is the third annual report providing the Governor and legislature with information on CPUC's and California investor-owned utilities' progress toward modernizing the state's electric grid.	http://www.cpuc.ca.gov/NR/rdonlyres/7AB03474-E27C-4EB6-AB8D-D610A649C029/0/SmartGridAnnualReport2012Final.pdf
The Future of the Grid: Evolving to Meet America's Needs. These materials were compiled in 2014 in advance of the "Future of the Grid—Evolving to Meet America's Needs National Summit." They consolidate key findings from four regional workshops that were held to obtain stakeholder views on the ways in which the grid must evolve to meet America's energy needs and customer expectations by the year 2030.	http://www.pdf.investintech.com/preview/92816eb2-f883-11e3-9de8-002590d31986/index.html
The Smart Grid Stakeholder Roundtable Group: Perspectives for Utilities and Others Implementing Smart Grids. This 2009 document provides general guiding principles for utilities and other smart grid project developers as they begin to plan and implement upgrades to their metering infrastructure and transmission and distribution networks, with the goal of helping developers better communicate how and why smart grid technologies will provide benefits.	http://www.epa.gov/cleanenergy/documents/suca/stakeholder_roundtable_sept09.pdf

Environmental Benefits and Other Policy Considerations

Title/Description	URL Address
Is It Smart If It's Not Clean? Strategies for Utility Distribution Systems. Part one of a two-part series on smart grid's potential benefits for energy efficiency and distributed generation. This issue letter discusses questions that PUCs and stakeholders can ask if they want smart grid investments to improve system distribution efficiency, focusing on CVR and optimizing voltage and var control.	http://www.raponline.org/document/download/id/656
Is It Smart If It's Not Clean? Smart Grid, Consumer Energy Efficiency, and Distributed Generation. Part two of a two-part series on smart grid's potential benefits for energy efficiency and distributed generation. This issue letter explains smart grid opportunities to advance end-use energy efficiency and clean distributed generation.	http://www.raponline.org/docs/RAP_Schwartz_SmartGrid_IsItSmart_PartTwo_2011_03.pdf

Title/Description	URL Address
Nation Association of Utility Regulatory Commissioners (NARUC) Smart Grid Resources. NARUC's website contains resources about smart grid deployment, including congressional testimony, reports, policies, and links to federal agencies.	http://www.naruc.org/smartgrid/
The Future of the Utility Industry and the Role of Energy Efficiency. This study estimates future electricity sales, identifies options for the future role of utilities, and evaluates the role of energy efficiency in the utility of the future.	http://www.aceee.org/research-report/u1404
Advancing Grid Modernization and Smart Grid Policy: A Discussion Paper. This white paper, developed from the Advanced Energy Economy Grid Modernization forum held in 2013, identifies the most relevant barriers to broader smart grid adoption, as well as corresponding policy options put forward for consideration.	http://info.aee.net/advancing-grid-modernization-and-smart-grid-policy
The Smart Grid: An Estimation of the Energy and CO_2 Benefits. This report highlights nine mechanisms by which the smart grid can reduce energy use and carbon impacts associated with electricity generation and delivery.	http://energyenvironment.pnnl.gov/news/pdf/PNNL-19112_Revision_1_Final.pdf
The Green Grid: Energy Savings and Carbon Emissions Reductions Enabled by a Smart Grid. This paper quantifies the energy savings and carbon dioxide emissions reduction impacts of smart grid infrastructure. Integrating Smart Distributed Energy Resources with Distribution Management Systems. This paper describes ongoing research by the Electric Power Research Institute to ensure that distribution management systems can more effectively use distributed energy resources.	http://www.smartgridnews.com/artman/uploads/1/SGNR_2009_EPRI_Green_Grid_June_2008.pdf http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001024360
Evaluation Framework for Smart Grid Deployment Plans: A Systematic Approach for Assessing Plans to Benefit Customers and the Environment. This document provides a template to evaluate the Smart Grid Deployment Plans that California's investor-owned utilities are required to file under CPUC's Decision 10-06-047.	http://www.edf.org/sites/default/files/smart-grid-evaluation-framework.pdf
Redefining Smart: Evaluating Clean Energy Opportunities from Products with Grid Connected Functionalities. This paper maps out clean energy opportunities for certain types of appliances and uses the framework as a tool to estimate the greenhouse gas emissions reduction potential of opportunities along the spectrum.	http://aceee.org/files/proceedings/2014/data/papers/11-969.pdf

Industry Resources

Title/Description	URL Address
Smart Grid Interoperability Panel (SGIP). SGIP is a public-private partnership with a mission to accelerate the implementation of interoperable smart grid devices and systems. Members develop standards to help educate key stakeholders on best practices, lessons learned, and vectors of influence affecting successful integration of next-generation smart grid technologies.	http://www.sgip.org
Smart Grid Demonstration—Integration of Distributed Energy Resources. This initiative conducts regional demonstrations and supports research focusing on smart grid activities related to integration of distributed energy resources. These resources include distributed generation, storage, renewable, and demand response technology.	http://smartgrid.epri.com/Demo.aspx
The Gridwise Alliance. Gridwise is a coalition of stakeholders that works to transform the electric grid by creating a venue for collaboration across the electricity industry. Gridwise provides a broad range of online resources about smart grid technologies and policies.	http://www.gridwise.org
National Electrical Manufacturers Association (NEMA). NEMA maintains a variety of smart grid fact sheets, as well as policy position papers that apply at the state and federal level.	http://www.nema.org/Policy/Energy/Smartgrid/Pages/default.aspx
Association for Demand Response & Smart Grid (ADS). This site provides links to ADS-generated reports and case studies, as well as major reports issued by government and others.	http://www.demandresponsesmartgrid.org/reports-research
Advanced Energy Management Alliance (AEMA) Demand Response Resources. AEMA is a demand response advocacy group that maintains a directory of industry demand response resources.	http://aem-alliance.org/demand-response/resources/
State Proceedings. The Energy Storage Association maintains a listing of state regulatory proceedings that relate to energy storage.	http://energystorage.org/policy/state-policy/state-proceedings?page=1

Understanding the Modern Grid

Title/Description	URL Address
What Is the Smart Grid? This website is a resource for information about the smart grid concepts and government-sponsored smart grid projects.	https://www.smartgrid.gov/the_smart_grid
Governors' Guide to Modernizing the Electric Power Grid. This paper looks at ways in which governors can help better understand and communicate the costs and benefits of grid modernization.	http://www.nga.org/cms/home/nga-center-for-best-practices/center-publications/page-eet-publications/col2-content/main-content-list/governors-guide-to-modernizing-t.html
The Smart Grid: An Introduction. This publication provides a "plain-English" exploration of the nature, challenges, opportunities, and necessity of smart grid implementation.	http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/DOE_SG_Book_Single_Pages.pdf

Title/Description	URL Address
Smart Grid. The Center for Climate and Energy Solutions is a nonprofit organization that advocates for policies and actions to address the twin challenges of energy and climate change. This fact sheet describes key smart grid technologies and applications, and explains how these components can provide economic and environmental benefits.	http://www.c2es.org/technology/factsheet/SmartGrid

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BPA. n.d. BPA Study of Smart Grid Economics Identifies Attractive Opportunities and Key Uncertainties. Bonneville Power Administration.	http://www.bpa.gov/Projects/Initiatives/SmartGrid/DocumentsSmartGrid/BPA-Smart-Grid-Regional-Business-Case-Summary-White-Paper.pdf
BPA. 2010. Transmission Asset Management Strategy. Bonneville Power Administration.	http://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/2010IPRDocuments/May%2017%20Transmission%20strategy%20for%20IPR2010.pdf
BPA. 2012. 2012 Update to the 2010–2014 Action Plan for Energy Efficiency. Bonneville Power Administration.	http://www.bpa.gov/EE/Policy/EEPlan/Documents/BPA_Action_Plan_FINAL_20120301.pdf
BPA. 2014. Energy Efficiency Implementation Manual. Bonneville Power Administration.	http://www.bpa.gov/EE/Policy/IManual/Documents/FINAL_October_2014_Implementation_Manual.pdf
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CPUC. 2014c. Annual Report to the Governor and the Legislature: California Smart Grid.	http://www.cpuc.ca.gov/NR/rdonlyres/2F5149C6-885A-4211-8CBA-A4F88F02CEA7/0/SmartGridAnnualReport2013final.pdf

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Glossary

Distribution systems deliver electricity to end customers. In the United States, the electric distribution system is alternating current at 60 Hz. At distribution substations, high-voltage electricity is received from the transmission system and converted into the lower-voltage electricity needed for distribution to customers. From distribution substations, distribution circuits (also called lines or feeders) are used to distribute electricity at a lower voltage. The secondary transformers on the distribution circuits are used to convert voltage to an even lower voltage for delivery to end customers. For residential customers, that voltage is 120 volts (+/- 5 percent).

Current is movement of electric charge, measured by the number of electrons passing a single point in one second.

- Alternating current is electricity that periodically reverses direction. In the United States, the alternating current is a 60 Hz sinusoidal wave form.
- Direct current is electricity flowing in a constant direction.

Voltage for an electrical system is the difference in electrical potential between any two points on the system.

Power is the rate at which energy is used (measured in watts or kilowatts); electric energy is usually sold by the kilowatt hour.

Reactive power occurs in alternating current systems when there is a shift between voltage and current (when voltage and current are not in phase). Reactive power must be supplied to most types of magnetic equipment (such as products with motors) and to compensate for the power losses in distribution and transmission systems. It typically is expressed in volt-ampere reactive (var).

Tools for a Modern Grid

No single technology or combination of technologies delivers modern grid benefits. How technologies and grid assets are managed is critical to achieving the promise of a modern grid. The following are some of the tools grid operators use to monitor, evaluate, and respond to grid conditions in real time.

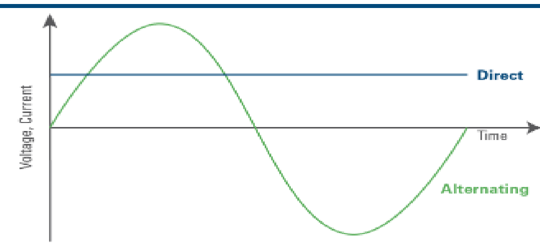
System controls include *load tap changers*, which are installed on transformers and raise or lower voltage at the beginning of the feeder; *voltage regulators*, which are installed on substations or feeders, and raise or lower downstream voltage; and *capacitor banks*, which are installed at the substation or feeder, and manage reactive power and voltage. *Control packages* are installed on capacitor banks and voltage regulators and programmed to turn on and off based on system conditions or via remote signal.

Monitoring devices include *voltage sensors* on distribution lines, *synchrophasers* on transmission systems for synchronized measurement of voltages, and (increasingly) *AMI meters* for voltage reaching consumer premises.

Communications and automation are enabled by *distribution management systems* that 1) receive information from multiple utility information systems (e.g., SCADA systems that monitor and control distributions systems and information systems that collect and store AMI data) and 2) analyze the data (on- or offline) to determine how to optimize the distribution system, and send control signals.

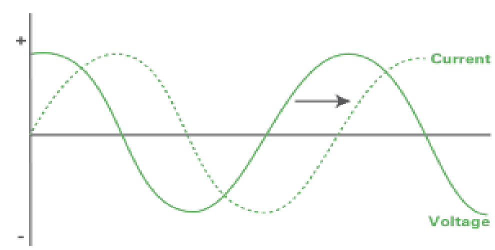
Adapted from DOE (2011).

Figure 7.5.1: Illustrative Overview of Direct and Alternating Current



Direct current is often depicted as a straight line. Alternating current is often depicted as a sine wave.

Figure 7.5.2: Illustrative Overview of Reactive Power



Reactive power occurs when voltage and current are out of phase.

Conservation voltage reduction is the reduction of feeder voltage (within allowable standards) on a distribution circuit to reduce energy consumption. CVR is different from voltage reduction required during periods of inadequate generation supply.

Volt/var optimization refers to the simultaneous and optimized control of voltage and reactive power (var) on the distribution system to minimize system losses.

Inverters convert direct current (DC) to alternating current (AC) electricity and vice versa. Inverters are used to connect renewables and storage to the electric grid. They require certain functionality to ensure safety.

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