Low-Carbon Power Sector Regulation: International Experience from Brazil, Europe, and the United States

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Introduction

The global electricity industry accounts for more than a third of the world's energy-related carbon emissions and two-thirds of the world's coal consumption.[1] Regulatory processes, decisions, and mechanisms deeply affect power sector investment, operations, and emissions in complex and sometimes subtle ways. Many aspects of regulation that are not explicitly intended to address climate or environmental concerns nevertheless have important effects on emissions. As a result, the topic of power sector regulation for emissions reduction requires a deep understanding of regulatory issues. This paper describes developments and trends in power sector regulation and their relationship to power sector emissions in the United States, European Union, and Brazil. We aim for a comprehensive survey, although the limited length of this report and the enormous range of the subject means that we have been somewhat selective. We have emphasized certain issues that should be of particular interest to a Chinese audience, given China's particular conditions and regulatory challenges.

The first sections of this paper outline several themes that we draw from our study of the three regions. We highlight major developments, debates, and examples of best practices in regulation that are important to emissions reduction. The middle sections provide detailed region-by-region analysis, and the concluding section briefly draws some implications for China.

A note on terminology is needed to set the stage for the discussion of regulatory issues in this paper. The term "regulation" can mean different things in different countries and different contexts. In particular, there is no clear dividing line between power sector "regulation" and power sector "policy." We take a broad view of regulation to include most government authority that affects the power sector, no matter whether that authority is exercised by executive government agencies, legislatures, independent bodies authorized by government, or judicial bodies. This authority may take a number of forms, including planning, standards-setting, price-setting, cost approval, market design, incentive mechanism design, permitting, monitoring, and enforcement. As we will see, difficulties in coordinating the efforts of different authorities is often a significant obstacle to emissions reduction.

[1] Ang et. al., 2011; Nalbandian and Dong, 2013.

1. Cross-Regional Themes and Developments

1.1 Planning for Low-Emissions Resources

In the regions covered in this paper, regulatory agencies are heavily involved in power sector planning, and the influence they wield has deep effects on power sector resource profiles, costs, and carbon emissions. All of these places are grappling with the question of how to mobilize adequate low-emissions resources as well as sufficient flexibility to support variable renewables. The power sectors in the United States, EU, and Brazil all feature some kind of planning to identify resources that will meet reliability, environmental, emissions, and other important goals, while minimizing cost and containing risk. However, there are big differences in the comprehensiveness of these planning processes. There are some examples of power sector plans that consider a full range of available resources and a full range of costs and benefits, including the social ("external") costs of emissions, but many national and subnational planning processes still fall short in this regard. In particular, this report highlights the theme of power sector plans that include consideration of end-use energy efficiency, which is typically a plentiful and cost-effective resource that can greatly contribute to achieving emissions-reduction goals and significantly reduce consumer electricity bills.

Our review of the United States emphasizes "integrated resource planning" (IRP), which is now practiced, in various forms and with varying degrees of success, in most states. In brief, a typical IRP process requires utilities to engage in a public process, overseen by regulatory agencies, in which *all* available supply-side *and* demand-side resources are evaluated on equal bases, in order to prepare a plan for meeting customer demand at lowest total societal cost. In many states, IRP has led to increased investment in end-use efficiency, as energy efficiency is typically a less expensive and cleaner alternative to new power plants. Some states (such as California) have gone as far as to declare energy efficiency the "priority resource" and require that power sector plans include "all cost-effective energy efficiency." However, even in the leading states, there is still much work to be done to fully integrate emissions externalities into the planning process and to identify and exploit all cost-effective energy efficiency.

In the EU, policy emphasizes a "liberalized" power industry structure, but regulatory agencies remain involved in planning in the sense of identifying desired outcomes, designing market mechanisms to deliver those outcomes, monitoring results, and making adjustments to the markets when they fail to achieve the desired results — although this process is often imperfect and contentious. The framework for energy efficiency, as laid out in the EU Directive on energy efficiency and energy services, is strong, but end-use energy efficiency resources are generally not well integrated with the planning for other resources (generation, transmission, and distribution), in terms of direct cost and benefit comparisons. As a result, there is a risk — already proving real in some areas — that EU countries could invest too little in energy efficiency in coming years and instead "overbuild" electricity generation and infrastructure.

As a developing country, Brazil faces the challenge of meeting rapidly growing demand. The country has developed a reasonably transparent planning process that has had some success in identifying and delivering adequate supply-side resources, including large amounts of renewables and significant transmission expansions, and in achieving a 99 percent electrification rate. Brazil has government-sponsored energy efficiency programs, and electricity distribution companies are obligated to achieve end-use efficiency targets, but energy efficiency resources are not comprehensively included in power sector planning.

1.2 Low-Emissions Resources: Acquisition, Pricing, and Funding

Mobilizing investment in the right mix of resources, as identified in planning efforts — we use the term "resource acquisition" in this paper to highlight the connection among investment choices, planning, and market design — requires careful attention to regulation, incentive mechanisms, and market design.

1.2.1 Energy Efficiency Resources

Across the regions covered in this paper, governments have placed obligations on electricity utilities to deliver end-use energy efficiency as a major component of their overall policies and strategies to achieve energy savings and reduce greenhouse gas emissions. These utility energy efficiency programs have delivered verified, reliable, and highly cost-effective resources, displacing the need for investment in supply-side generation, transmission, and distribution resources. They have also been well-documented to inexpensively and reliably reduce air and water impacts of electricity production. In fact, in many cases, regulatory agencies regard these programs as equivalent to the construction of virtual "efficiency power plants" that help meet projected demand in the same way that conventional power plants would. In some leading US states, utilities are obligated to achieve energy savings as high as 2.5 percent of annual sales, with even higher obligations under consideration. Requiring utilities to invest in end-use energy efficiency raises important questions about utility profits and business models, and, particularly in the United States, regulatory agencies have designed incentive mechanisms to align the utility's profit motivation with the objective of promoting end-use energy efficiency.

Placing obligations on electricity utilities enables the delivery of energy savings and emissions reductions without requiring direct government funding, instead funding energy efficiency in a way analogous to the funding of conventional power plants — that is, through customer electricity bills. For example, in the United Kingdom, the costs of meeting the obligations are considered a "cost of doing business" by electricity and gas suppliers and so are reflected in the prices charged to end-use customers. In California, about one-quarter of utility energy efficiency portfolio budgets is funded by a "public benefits charge" that appears as a separate item on customer bills, and the remaining majority of the utility energy efficiency programs is funded through utility resource procurement funds — i.e., the same funds (paid by end-use electricity consumers) that would otherwise be used to pay for conventional power stations and grid expansion. In Brazil, all utility energy efficiency projects initially were funded by a public benefits charge similar to that of California. More recently, utilities have been allowed to recover some of their energy efficiency expenditures by using performance contracts with the owners of the facilities where the projects were implemented. Part of the funds recovered by the utilities could be used for new energy efficiency projects, and part to reduce electricity prices for consumers.

1.2.2 Renewable Energy Resources

Different approaches to supporting renewable energy investment have worked in different places. It is clear from the experience in the United States, EU, and Brazil that careful attention to design and implementation is more important than the broad choice among a feed-in tariff (FIT), renewable portfolio standard (RPS), or other approaches.

The FIT has been relatively widespread in the EU, although less common in the United States. This approach require retailers or utilities (more specifically, "load-serving entities") to purchase electricity from eligible renewable energy technologies for long terms (usually 15 to 20 years), at either fixed prices typically set equal to the expected cost of production plus a profit (return on investment) or at a premium over market prices. In recent years, at least in part because of rapid gains in both renewable generation capacity and the cost competitiveness of renewables, several countries in the EU have modified, rolled back, or even repealed FIT requirements. However, the FITs have proven to be highly effective, when designed well. In the best cases, governments have pre-defined processes to frequently review the FIT and, if necessary, adjust prices, for example in reaction to faster-than-expected reductions in technology costs. In addition, some places have had success with automatic, periodic FIT reductions.

An RPS is another option that is more common in the United States. (Where they have been used in Europe, they are often referred to as "quota schemes.") They require load-serving entities to supply a minimum percentage or specified amount of their retail load with qualified (usually non-hydro in the US case) renewable energy resources. RPS is the inverse of the FIT approach, targeting quantity instead of price. As with FITs, the devil is in the details. The best examples feature stability and clarity (given that frequent changes can damage investor confidence), include clear rules about what resources and technologies are eligible for the RPS, are broad-based (covering all utilities and retailers in a state or country), and have effective verification and strong enforcement.

After earlier use of a FIT-like mechanism, Brazil currently manages generation capacity development (including both hydro and non-hydro renewables) through auctioning of long-term contracts —a reasonably transparent and competitive approach that includes safeguards to ensure that bidders have the technical and financial ability to fulfill promised price and delivery terms.

1.3 Renewable Energy Integration

All three regions face a challenge of integrating large and rapidly growing amounts of energy from renewable sources whose output is variable. Studies show that high penetration of variable renewables is feasible and cost-effective, even with existing technologies. Strategies for integration include creation of larger balancing areas, development of new transmission capacity, development and advancement of wind and solar forecasting, design and implementation of grid codes, time-differentiated pricing, implementation of energy storage options, and shorter scheduling and dispatch intervals.

Closely related to the acquisition of (that is, investment in) renewables is the acquisition of sufficiently flexible resources to facilitate the integration of variable renewable production. There is a need for some combination of regulatory approaches, changes in grid operations, and market mechanisms that will promote a shift to a more flexible portfolio of non-renewable resources (including responsive demand) to support the growth of renewables. As a result, regulatory agencies, industry, and other stakeholders have been engaged in efforts to shape such approaches and mechanisms. In the EU's liberalized markets, as well as in "restructured" markets in the United States, these debates have focused on improvements to energy and ancillary service markets pricing, capacity market reforms, changes in grid operations, or, in some cases, enacting specialized mechanisms to promote investment in flexible generation.[2] Brazil has perhaps been under less pressure in this regard because its plentiful (and relatively flexible) hydro resources are a good complement to its non-hydro renewables.

[2] Hogan, 2012.

1.4 Generator Dispatch

How a given portfolio of generation resources is deployed on a day-by-day and hour-by-hour basis can have big effects on carbon emissions. Moreover, dispatch approaches influence investment decisions, market outcomes, and the planning process. Regulatory agencies play an important role in influencing — if not setting — dispatch models. In all of the jurisdictions discussed here — and indeed in almost all major countries in the world — the basic dispatch approach is to rank generators according to variable costs, so that the system operator calls on lower-operating-cost generators first. One factor is particularly important for power sector emissions: the degree to which emissions costs and other external costs are included in the variable costs considered in the merit order ranking process.

1.5 Carbon Trading and Carbon Pricing

Beginning in 1990, when it was first introduced to address emissions of sulfur dioxide under the US Clean Air Act, emissions trading (also known as cap-and-trade) has been adopted in a number of places in the world, addressing a variety of pollutants. The EU launched a greenhouse gas emissions trading scheme (ETS) in 2005, and a number of US states have followed. Carbon emissions from power generation have been a central concern in each of these GHG cap-and-trade schemes.

A few observations about ETSs are worth emphasizing here:

- An ETS can work well as a backstop for a portfolio of policies, ensuring that an emissions reduction target will be met. Policies to mobilize energy efficiency and renewable resources can be designed to provide reliable emissions reductions, while the ETS cap acts as a binding constraint. In this way, the ETS cap ensures that the emission reduction objective is met, even if the other policies in the portfolio over- or under-perform.
- Policies supporting investment in energy efficiency can play a particularly important role due to market failures. High energy prices are typically required to motivate end-users to investment in energy efficiency, even though energy efficiency investments are typically cost-effective.
- Auctioning emission allowances has an important advantage over free allocation of allowances: It raises revenue that can be used for socially beneficial purposes. The power sector cap-and-trade scheme in the northeast US has had success with “recycling” these auction revenues into end-use energy efficiency programs, largely administered by power sector utilities or other public service entities.

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2. United States

There is significant variation across states in terms of regulation and carbon emissions-reduction policies. The sections that follow this overview will discuss some key examples that highlight lessons learned as regulatory policy has developed across the states.[3] We focus on examples from states that have been the most innovative and successful with emission reductions, although we also discuss "lagging" states in some cases.

2.1 Institutions and Functions

Figure 1 outlines the institutions involved in regulation and policymaking in the US power sector. State public utility commissions (PUCs) take much responsibility for regulation, although federal agencies also play important roles. State PUCs are legally independent from other branches of government (both state and federal). They oversee and approve retail prices, utility revenue, procurement and construction plans, and utility-run programs for end-use energy efficiency.[4] State PUCs also often monitor and enforce utility and load-serving entity progress against environmental goals, using tools such as an RPS (introduced earlier and discussed in detail below). Broadly speaking, the regulation overseen by PUCs is intended to ensure that utilities provide safe, adequate, and reliable service at prices (or revenues) that are sufficient, but no more than sufficient, to compensate the regulated firm for the costs (including returns on investment) that it incurs in serving its customers. The roles of regulators and utilities have evolved through a long series of court decisions.

An important feature of utility regulation in the United States (and elsewhere) is that its form encourages management to perform in ways that may or may not match long-term interests of ratepayers and the public. In effect, policymakers and regulators have come to recognize that "all regulation is incentive regulation." That is — at least in "best practice" cases — utility regulators see an important part of their task as aligning the behavior of profit-seeking utilities with social and environmental goals.

A key task of the state regulatory agency is to set prices using the criteria outlined above. Another aspect of this task is to give the utility the right incentives to align its behavior with the overall objectives of power sector policy. Over recent decades, policymakers have transformed the way that utilities are regulated in order to correct disincentives, and provide positive incentives, for utilities to invest in end-use energy efficiency.

Federal statutes such as the Federal Power Act and the Clean Air Act provide federal agencies some regulatory powers and oversight responsibilities. The Federal Energy Regulatory Commission (FERC) has jurisdiction over the rates, terms, and conditions of transmission and wholesale power in interstate commerce. Past court decisions and subsequent FERC orders give the commission expansive authority

[3] For more detail see Lazar, 2011.

[4] Note that there are some exceptions to PUC authority: About 75 percent of US electricity consumption is served by privately owned and profit-driven entities, known as investor-owned utilities, that are regulated by PUCs; the balance is sold by a mix of municipal utilities, public power districts of various kinds, and electricity cooperatives that are largely self-regulated and exempt from some or all elements of state price regulation.

over transmission and distribution lines that could participate in wholesale transactions.[5] FERC also oversees hydro dam licensing safety and natural gas and oil pipeline transportation rates and services.[6]

Figure 1: Key Institutions Active in the US Electric Sector

State Governments and Regional Organizations

Public Utility Commissions
- Leading responsibility for utility regulation and oversight of planning
- Independent from state executive branch

Air Quality Regulatory Agencies
- Sets state emission rules; issues and enforces permits

Energy Offices
- Part of state executive branch; participates in NERC planning

Regional Entities under the North American Electric Reliability Corporation

Regional Transmission Organizations (also called independent system operators)

Federal Government

US Environmental Protection Agency
- Sets national standards for emissions (conventional and GHG) under the Clean Air Act

Federal Electricity Regulatory Commission (FERC)
- Jurisdiction over interstate issues, including transmission and wholesale markets.
- Oversees hydro licensing

Department of Energy
- Little direct role in power sector regulation; minor role in regulation (with FERC) of international electricity trade
- Authority to adopt energy efficiency standards
- Supports research and development

Under the Clean Air Act, the US Environmental Protection Agency sets air quality standards from mobile and stationary sources. In 2007, the Supreme Court ruled that carbon dioxide is a pollutant and therefore able to be regulated by EPA under the Clean Air Act. In September 2013, EPA put forward carbon pollution standards for new natural gas turbines and coal plants.[7] In June 2014, EPA issued a proposed carbon standard for existing power plants. (See Section 2.9 for more detail.) These Clean Air Act emissions standards have become an important mechanism for carbon emissions reduction from the power sector in light of the lack of new legislation that specifically addresses GHG emissions.

EPA sets standards for hazardous and non-hazardous emissions, such as sulphur dioxide, nitrogen oxide, ozone, volatile organic compounds, and mercury, among others. State air quality agencies must create and implement implementation plans for meeting the emission standards. EPA reviews and approves

[5] Federal Energy Regulatory Commission, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, April 24, 1996, http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp.

[6] Lawrence Greenfield, *An Overview of the Federal Energy Regulatory Commission and Federal Regulation of Public Utilities in the United States*, December 2010,

[7] U.S. Environmental Protection Agency, *2013 Proposed Carbon Pollution Standards for New Power Plants*, http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants.

these plans; the agency can also issue its own implementation plan for a state if the state plan does not meet Clean Air Act requirements.[8]

2.2 Power Sector Structure

The industrial structure of the power sector in the US features numerous regional utilities. These utilities vary in terms of size, degree of vertical integration, and other characteristics, but in much of the country a typical utility may be described as an electricity distribution and retail company that acquires resources, as identified in a planning process (see below), to serve customers in a particular geographic area.

States vary in the degree to which they have "restructured" the electricity industry by breaking up vertically integrated utilities and introducing competitive wholesale and retail markets.[9] Before the late 1990s, the United States was dominated by vertically-integrated utilities, typically not operating across state borders. Since then, the country has witnessed a divergence of industry models. In the West and Southeast, the vertically integrated utility model remains dominant, and there are still a large number of single-utility balancing areas. In the East, Midwest, and California, utilities in some cases divested their generation and joined wholesale electricity markets that extend across multiple states. These markets are operated by independent system operators (ISOs).[10] Figure 2 describes the status of the various industry segments in different states.

It is important to recognize that some states that have decided *not* to pursue this specific definition of "restructuring," have still been very successful and innovative in the key regulatory tasks of limiting power sector costs and reducing power sector emissions. As we will see in the following sections, some "best practice" examples of certain aspects of regulation come from states that have *not* pursued restructuring (such as Washington) or have suspended restructuring (such as California).

Utilities acquire the resources identified in the planning process in different ways (or combinations of ways) depending, in part, on the regulatory regime of the state. As mentioned above, some utilities (in states that are not restructured) are vertically integrated – that is, they build power plants or acquire power, under long-term contracts, from independent companies that build power plants, using competitive bidding processes closely overseen by regulators.[11] In states that have restructured, the utilities have the option to buy electricity from competitive wholesale markets – although even in these states, the utilities often hedge against price fluctuations by entering into long-term contracts with owners of power plants to buy electricity at agreed prices.[12] In states where end-use energy efficiency is considered a resource, utilities typically are responsible for the programs that acquire the energy efficiency. These energy efficiency programs have been very successful at reducing power sector costs[13]

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[8] See US Environmental Protection Agency, *Understanding the Clean Air Act*, http://www.epa.gov/air/caa/peg/understand.html.

[9] Restructuring is a commonly used term in the US that, in essence, is very similar to the word "liberalization" as it is used in the European context.

[10] US terminology also includes "regional transmission organizations" (RTOs), which, broadly speaking, are very similar to ISOs.

[11] Hibben et al., 2011.

[12] The same is true for states that have not restructured, but whose utilities are members of an organized wholesale power market. That is, vertically integrated utilities in non-restructured states can purchase a share of their electricity needs through short-term purchases of energy from organized power markets.

[13] Molina, 2014.

and reducing emissions, although there is still much opportunity for expansion, even in the states that have the best energy efficiency records.

Most electricity in the United States is generated by coal (37 percent of the generation mix in 2012), natural gas (30 percent), nuclear power plants (19 percent) and hydropower (7 percent), with increasing amounts from renewable resources such as wind and solar. Recently, there has been debate about how to design markets and incentive mechanisms that will meet the urgent task of delivering the type and quality of capacity needed to support renewables.[14]

Figure 2: US Power Industry Segments

Industry Segment				Representative States
G	**T**	**D**	**R**	
G-T-D-R				Alabama, Arizona, Florida, Idaho, Colorado, Utah, Montana, New Mexico, Kentucky, Mississippi, Nevada, Oregon, Washington
G	T-D-R			PJM (Virginia, West Virginia); SPP (parts or all of Arkansas, Louisiana, Mississippi, Missouri, Nebraska, New Mexico, Oklahoma and Texas), Kansas, Nebraska, Oklahoma; MISO (parts or all of Arkansas, North Dakota, South Dakota, Indiana, Illinois, Wisconsin, Minnesota, Michigan, Missouri, Nebraska, Louisiana, and Mississippi), California
G	T-D		R	PJM (Delaware, Maryland, New Jersey, Ohio, Pennsylvania); ERCOT (Texas)

Abbreviations: *G = generation, T = transmission, D=distribution, R = retail; PJM, CAISO, MISO, SPP, and ERCOT are regional transmission organizations and independent system operators.*

In most states, retail functions, including marketing and customer billing, are treated as monopoly services. In these states, end users have no choice but to buy electricity from the utility in their region. However, 15 states (as well as the District of Columbia) allow retail companies to compete for

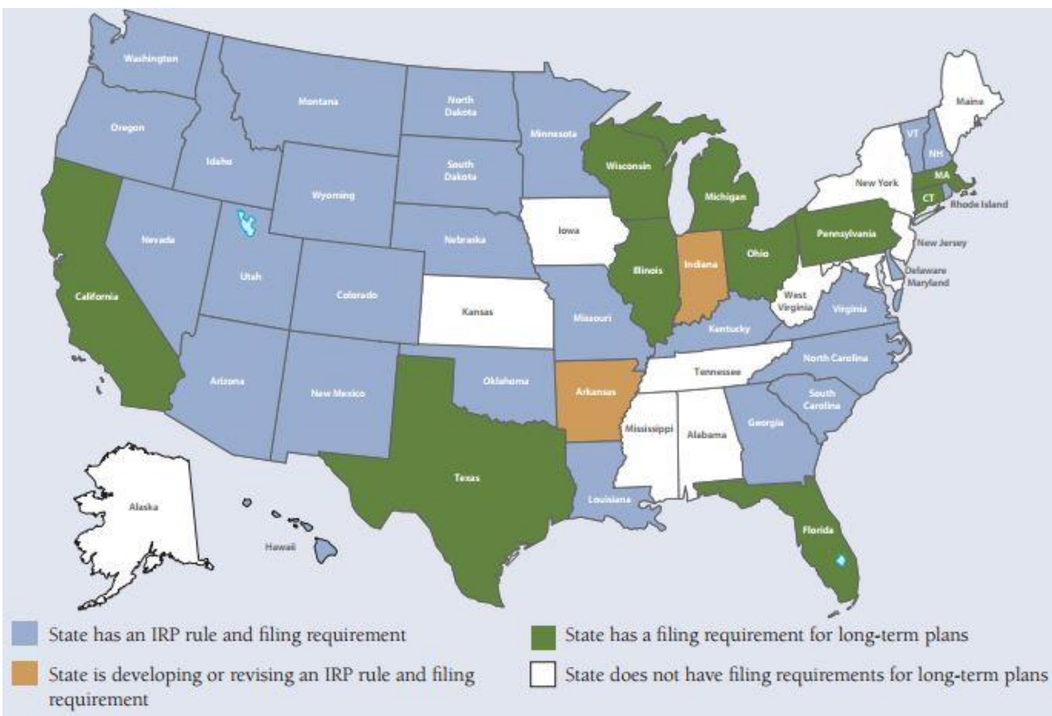
[14] See Regulatory Assistance Project (2012), *Beyond Capacity Markets.* Retrieved from http://www.raponline.org/featured-work/beyond-capacity-markets-delivering-capability-resources-to-europes-decarbonised-power.

customers.[15] In these states, the utilities provide distribution service to all customers and also (in most states) offer a "default" retail service; state regulators still oversee these functions. Other entities offer competing retail services that are not subject to regulation. Because the utilities do not serve all customers in their distribution areas, resource planning can be somewhat more complicated, and there has been much discussion about how regulatory agencies can still ensure that comprehensive planning includes energy efficiency as a resource.[16]

2.3 Power Sector Planning

Power sector regulation and planning are closely related, and cooperation among regulators, utilities, and other stakeholders in a well-designed planning process is essential for the development of a low-carbon power sector. In the United States, planning is important in all states — regardless of the degree of "restructuring" or liberalization of retail and wholesale markets — because decision-makers need to be sure that their policies achieve objectives as intended and at the lowest possible overall cost for society as a whole. All utilities and retailers perform some form of long-range planning for resources to serve customers — including projections of baseline electricity demand — although there is a great degree of variation across utilities and states in comprehensiveness of this planning as well as variation in cooperation with regulators and other stakeholders in the planning process.

Figure 3: Integrated Resource Planning in the United States



Source: RAP, 2013. See www.raponline.org/document/download/id/6608.

[15] This "deregulation" began in the 1990s. See US EIA (2010), *Status of Electricity Restructuring by State*. Retrieved from www.eia.gov/cneaf/electricity/page/restructuring/restructure_elect.html.

[16] For more information on these issues, see SEE Action (2011), *Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures.*

While there are various aspects of and approaches to planning in the United States, this section focuses on the concept of "integrated resource planning" (IRP), which began in the 1980s and has emerged as an important tool for emissions reduction and for cost containment. It is now practiced in various forms in the majority of states, as shown in Figure 3.

The main idea of IRP is to prepare a cost-effective plan for meeting customer demand by comparing available supply-side *and* demand-side resources on an equal basis. Inclusion of demand-side resources — particularly end-use energy efficiency — into the power sector planning process has led to increased investment in end-use efficiency, as energy efficiency is typically a less expensive and cleaner alternative to new power plants. IRP is in some ways more straightforward in states without retail competition — i.e., where each utility is responsible for all retail sales in its service territory. However, states that have restructured (i.e., liberalized) retail markets, by allowing multiple retail companies to compete against the utility in each service territory, have also implemented forms of IRP. In those states, the integration of supply-side and demand-side resources is most relevant to the legacy "default" service provided by the utility, which continues to include bundled supply-side resources in addition to the wires.[17] However, a form of IRP focused on the transmission and distribution system also integrates energy efficiency and demand-side resources to manage or defer investments in the distribution system.

The basic components of the IRP approach (as shown in Figure 4) are:

- Forecast baseline peak and energy demand;
- Determine available resources and costs. Resource options include conventional power plants and end-use energy efficiency, as well as investments in distribution and transmission lines. Costs may include externalities such as carbon and conventional emissions costs.
- Find the most cost-effective mix to meet forecasted needs.
- Analyze risks through scenario and sensitivity analysis. Risks may include variation in factors such as fuel prices, externality costs, load growth, and hydro conditions.
- Collect and adjust for stakeholder input through various stages of the planning process.

Not all states have done a good job of implementing this type of integrated planning, and there is much work to be done to ensure that demand-side options and external costs are fully considered.

The Northwest Power and Conservation Council (NPCC), leads the planning efforts in the region consisting of four states: Washington, Oregon, Idaho, and Montana.[18] The region's planning approach has become gradually more sophisticated since the NPCC's creation in 1980, but, from the beginning the council's work has been based on the legal requirement to consider the full costs associated various resource options, including environmental costs. In addition, the planning process is required by law to treat energy efficiency not just as a resource, but a "priority" resource.[19]

Since its inception, the NPCC has issued six plans. The 2010 plan looks at how thousands of different possible resource combinations and considers the total (internal and external) costs of each of these. To deal with risk, the council evaluates how the costs would vary under hundreds of hypothetical scenarios,

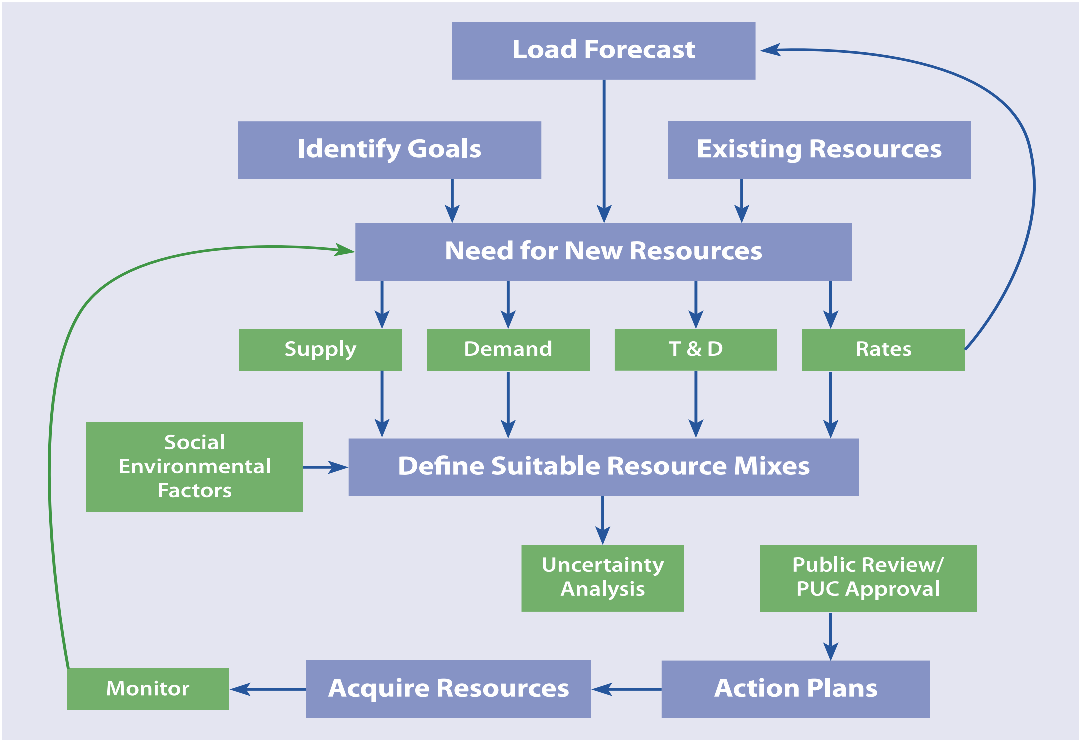
[17] State and Local Energy Efficiency Action Network, 2011.

[18] See NPCC, 2011, for more detail. Note that in most cases, the utilities in the region are still required to prepare and submit utility-level IRPs to the state PUCs. The council's plan serves as an important input to these plans, and also as a basis against which the PUCs can evaluate them.

[19] The legislation that established the planning process for the region is available at: http://www.nwcouncil.org/reports/poweract/.

all over a 20-year planning horizon. The 2010 plan concluded that 85 percent of baseline demand growth could be met through energy efficiency.[20]

Figure 4: Flow Chart for Integrated Resource Planning



Source: RAP, 2013: http://www.raponline.org/document/download/id/6608.

Transmission planning in the United States is coordinated by eight regional entities associated with the North American Electric Reliability Corporation, which derive authority for setting reliability standards from FERC's oversight of interstate transmission. The councils work closely with the regional transmission organizations (RTOs), independent system operators (ISOs), and individual utility balancing area operators that are responsible for various balancing areas that cover the United States.[21] In addition, there is some overlap with the IRPs developed by individual utilities, which increasingly take transmission resources into account. Transmission assets are owned by a patchwork of public and private organizations. In parts of the United States, poor transmission planning — partly due to the power of industry special interests in the planning process have, at times, hampered the development of a low-cost grid that supports renewables and emissions reduction. For states and utilities that fall outside of RTOs, there has often been resistance to a regional approach to transmission planning. Depending on local circumstance, increased transmission typically supports larger trading regions that lower costs for high-cost regions while potentially raising them for lower-cost regions, even while overall costs fall. Since approval of transmission historically relied on local decision-makers, states adversely

[20] For more information on planning in this region, and IRP more generally, see: RAP (2013), Policy Recommendations", Lamont and Gerhard 2013 www.raponline.org/document/download/id/6368, Taylor et al, 2012 www.iipnetwork.org/IIP_resource_acquisition.

[21] For more detail, see National Council on Electricity Policy (2004), *Electricity Transmission: A Primer.*

impacted could hold up sound transmission projects. Better regional transmission (multistate) planning offers a promising path forward.

A very important recent development in transmission planning is FERC's Order 1000 of 2011, which requires transmission planners to: 1) permit input from all public stakeholders; 2) consider how transmission plans can support "public policy" objectives for renewables, energy efficiency, and environmental concerns; and 3) and consider using "non-transmission alternatives," including end-use energy efficiency and demand response, that can cost-effectively displace the need for transmission projects.

2.4 Energy Efficiency Resources: Acquisition, Pricing, and Funding

Development and implementation of end-use energy efficiency policies and programs in the United States, at both the federal and state levels, began as a response to the oil price shocks in the 1970s. Beginning at this time, a range of federal legislation set energy efficiency standards for appliances and equipment, set design standards for commercial new construction, and established processes for advancing those standards.[22] Subsequent federal legislation has also addressed energy-efficient building codes, energy efficiency in low-income households, and energy efficiency tax credits.

In the early 1980s, energy utility regulators in many states began requiring utilities to assist their customers to improve the energy efficiency of their properties. Since the mid-1980s, utility-delivered programs have been an important mechanism for energy efficiency retrofits in the United States, with investment in these programs in 2012 estimated at approximately $6 billion[23] across the country. (See also Figure 5 and Downs et al., 2013.) Utility energy efficiency programs mostly started in regions of the United States with high energy costs, such as New England, the upper Midwest, and California, as well as in the Pacific Northwest, which despite of low energy costs historically has managed its electric grid through regional IRP that placed an emphasis on energy efficiency.

State-level regulations typically require utilities to supply energy services to customers at the lowest cost possible. This makes utility energy efficiency programs viable, as a wide range of efficiency resources typically cost less than the available supply-side options.[24] Sometimes regulated utilities receive a rate of return on investments in demand-side resources comparable with supply-side investments. Alternatively, utilities may receive performance incentive payments for meeting and exceeding energy efficiency targets, or penalties for not meeting targets.

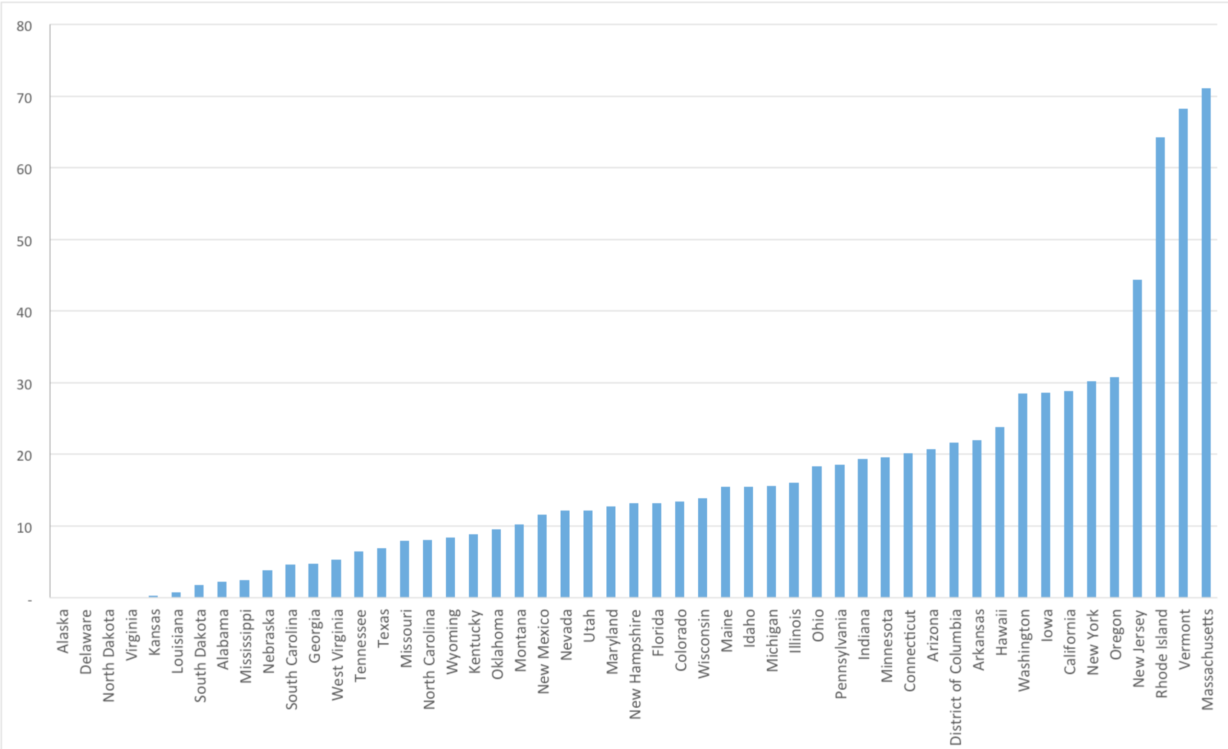
Cost-effectiveness is a primary goal of US utilities' energy efficiency programs. Although public demand for energy efficiency, customer service, and environmental goals can be important drivers, all programs must offer cost-effective energy and demand savings to meet the industry's least-cost requirements. To ensure cost-effectiveness, independent program evaluators review utility energy efficiency programs under rigorous benefit/cost rules that examine the stream of energy saving benefits provided by the programs over the expected lifetimes of the energy efficiency measures, against the costs of installing the measures.

22 This legislation includes the *Energy Policy and Conservation Act 1975* (Public Law 94–163); the *Energy Conservation and Production Act 1976* (Public Law 94–385); and the *Energy Policy Act 2005* (Public Law 109–58).

23 Downs et al., 2013.

24 Molina, 2014.

Figure 5: Annual Per-Capita Utility Investment in Energy Efficiency Programs by State (Budgeted USD for 2013)



Sources: Consortium for Energy Efficiency and US Bureau of the Census

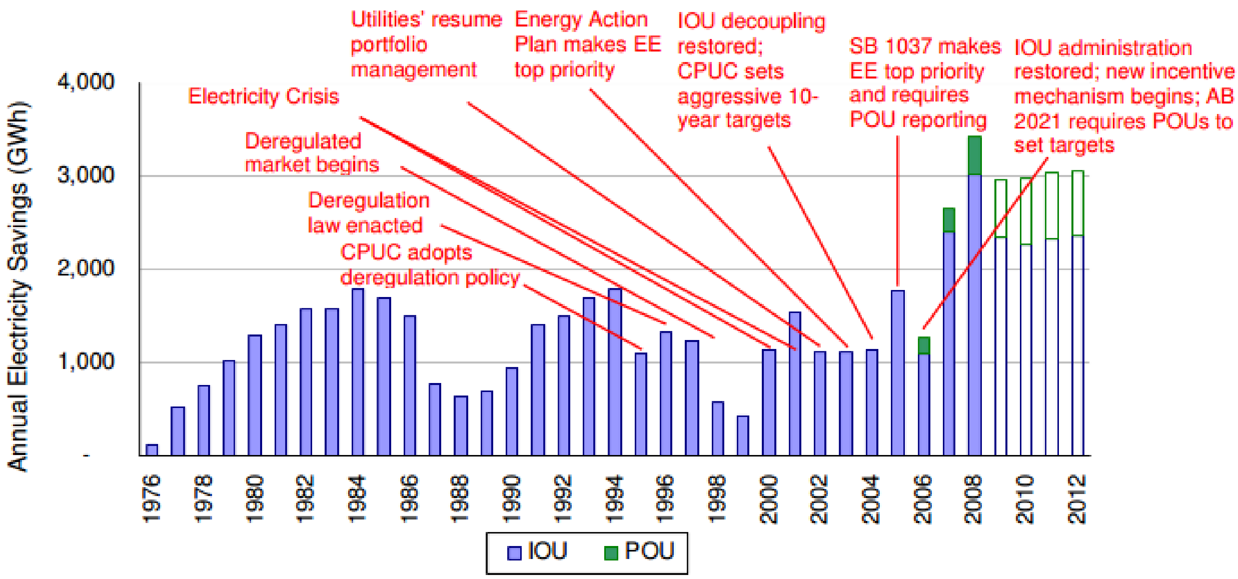
A private-public initiative, the National Action Plan for Energy Efficiency,[25] was developed in July 2006 to create a national commitment to energy efficiency through the collaborative efforts of gas and electric utilities, utility regulators, and other partner organizations. The Action Plan is significant as an effort to address energy efficiency at the national level, in a country where much of the policy progress has been at the state level. It was led by a diverse Leadership Group of more than 60 leading gas and electric utilities, state agencies, energy consumers, energy service providers, environmental groups, and energy efficiency organizations. The Leadership Group identified key barriers limiting greater investment in cost-effective energy efficiency, made policy recommendations to overcome the barriers, and documented policy and regulatory options for greater attention and investment in energy efficiency.

2.4.1 Case Study: California Utility Energy Efficiency Programs

California is a good example of best practice in utility energy efficiency program implementation. In California, these programs date back to the 1970s and have grown and evolved substantially over four decades (see Figure 6).

[25] Leadership Group, 2006.

Figure 6. Annual Electricity Savings From California Utility Energy Efficiency Programs[26]



Note: Comprehensive data on POU efficiency savings is only available beginning in 2006; however, many POUs have offered programs for decades. IOUs provide approximately 75% of the state's electricity and POUs provide approximately 25%.[49]

Both investor-owned utilities (IOUs) and publicly owned utilities (POUs) in California administer energy efficiency programs with oversight by the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC). The commissions establish key policies and guidelines, establish targets for statewide annual energy efficiency savings and demand reduction, set program goals, and approve spending levels.[27]

California law mandates that utilities acquire all cost-effective energy efficiency,[28] and CPUC and CEC take an active role in identifying opportunities to do so. The utilities implement a broad range of energy efficiency programs directed at customers across all sectors of the economy: residential, commercial, industrial, and agricultural.

California has established energy efficiency as its highest priority energy resource for procurement of new resources. In 2003, the CPUC, in collaboration with the CEC, issued its first Energy Action Plan (EAP)[29] in response to the crisis in California's energy markets, as a high-level, integrated framework to meet California's energy and natural gas needs.[30] The EAP is a "living" document, and there have been two subsequent versions issued since 2003.

[26] Martinez, Wang, and Chou, 2010.
[27] American Council for an Energy-Efficient Economy, 2014.
[28] California Legislature, 2006.
[29] State of California, 2003.
[30] CPUC, 2010.

The initial EAP established a loading order[31] to define future efforts to meet California's energy needs. The loading order stipulated that the state would acquire first all cost-effective energy efficiency resources, then use cost-effective renewable resources, and only after that, use conventional energy sources to meet new load.[32] The loading order policy was codified by statute in 2005.[33] The loading order puts energy efficiency first because it is believed to be the lowest-cost, environmentally preferred resource.[34]

In 2008, the CPUC published the *California Long Term Energy Efficiency Strategic Plan.*[35] The *Plan* was developed through a collaborative process involving major utilities and over 500 individuals and organizations. The *Plan* establishes a roadmap for energy efficiency in California through the year 2020 and beyond. It articulates a vision and goals for each economic sector and identifies specific strategies to assist in achieving those goals.

CPUC Decision 09-09-047 approved utility energy efficiency portfolio plans for the period 2010 to 2012 to support the strategic plan. In particular, the CPUC required the IOUs to administer 12 statewide programs that will be consistent throughout all the obligated utilities' service areas as well as some local and pilot programs.[36] The statewide programs include an array of energy efficiency measures in the following categories: residential; commercial; industrial; agricultural; new construction; lighting; heating, ventilation, and air conditioning; codes and standards; DSM integration and coordination; workforce education and training; marketing, education, and outreach; and emerging technologies. The residential Statewide Program for Energy Efficiency offers a tiered suite of savings options designed to leverage municipal funding programs, federal stimulus dollars, and related programs of the California Energy Commission with a goal of 20 percent savings in up to 120,000 homes.

From 1996, California's utilities collected a public benefits charge on customer utility bills to fund utility energy efficiency programs. The charge for electricity was about $0.003/kWh, capped at three percent of a customer's bill. The public benefits charge was not reauthorized by the California Legislature in 2011, and Governor Jerry Brown directed the CPUC to pursue continuation of funding for these programs before the charge expired. About one-quarter of the utility energy efficiency portfolio budgets was funded by the public benefits charge; the remaining majority of the utility energy efficiency programs was funded through utility resource procurement funds and is unaffected by the expiration of the charge.[37] Utility resource procurement budgets are recovered through rate cases brought before the CPUC.

In September 2009, the CPUC approved a $3.1 billion IOU energy efficiency program budget for 2010 to 2012 — a 42 percent increase over the previous three-year period.[38] The publicly owned utilities budgeted USD 150 million for the fiscal year 2008–2009. Roughly 79 percent of customers and 73

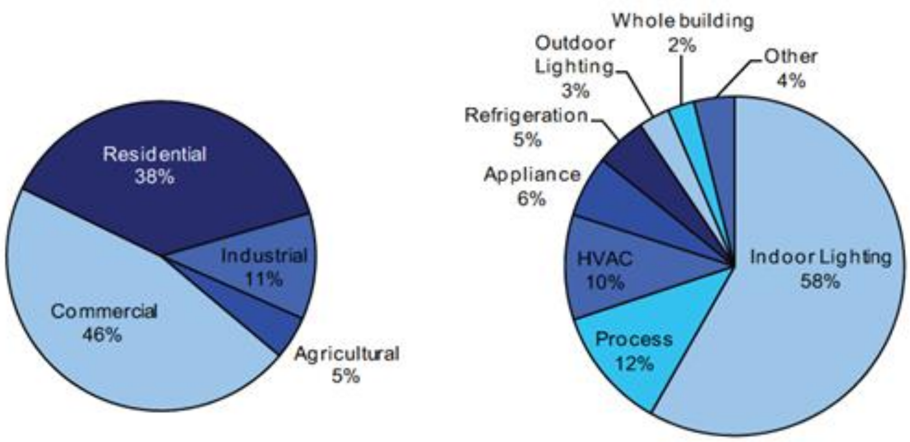
[31] Although the term "loading order" is often used to describe the dynamic process used by system operators to meet demand on a short-term basis, in California the term is applied to the process whereby energy utilities acquire resources over the long term.
[32] California Energy Commission, 2005.
[33] California Energy Commission, 2005.
[34] Hopper, Barbose, Goldman, and Schlegel, 2009.
[35] CPUC, 2008. There is a long time lag for final verification of data; as a result, this is the latest available fully verified data.
[36] CPUC, 2009.
[37] American Council for an Energy-Efficient Economy, 2014.
[38] CPUC, 2009.

percent of sales are accounted for by IOU utilities. Four percent of the energy efficiency budget is allocated to evaluation, measurement, and verification of energy savings.

In addition, for the period 2010 to 2012, $260 million in funding was directed to government entities for local efforts targeting public sector building retrofits and innovative energy efficiency opportunities, and $175 million was earmarked to launch California's programs to help homes and buildings achieve "zero net energy" status.[39]

For the 2006–2008 program cycle, the total $2.1 billion investment by IOU ratepayers in energy efficiency resulted in more than 6,000 GWh and 1,100 MW in annual energy savings for program participants over the three-year program cycle. Over the life of the energy efficiency measures installed by program participants, the savings are estimated to be more than 66,000 GWh[40]. Figure 7 shows a detailed breakdown.

Figure 7. Electricity (GWh) Savings from California IOU Energy Efficiency Programs During the 2006–2008 Program Cycle[41]



2.4.2 Revenue Regulation, Utility Incentives, and Energy Efficiency

A core function of US regulatory agencies is to establish mechanisms and procedures to 1) allow the utility an opportunity to earn sufficient (but no more than sufficient) revenue; 2) establish consumer prices that can provide that revenue; 3) align the behavior of the utilities and consumers with public policy objectives, including energy savings and emissions reduction. This section focuses on an aspect that is particularly important to overall power sector emissions: how the revenue approval process affects utility incentives to support end-use energy efficiency.

Under the traditional approach, officials periodically hold reviews (also known as a "rate case") and call on the utility to provide information on costs, in order to determine the total amount of revenue the utility should be allowed to receive as a "fair" rate of return on its investment given projected sales.

[39] CPUC, 2009.
[40] CPUC, 2010.
[41] CPUC, 2010.

More specifically, the traditional formula for determining revenue requirement may be expressed as:[42]

Approved Investment x Approved Rate of Return + Approved Operating Expenses = Approved Revenue

Officials then set prices such that, if sales materialize as projected, utilities will receive the approved revenue. In practice, under this traditional approach, the actual revenue the utility receives in a given period between rate cases may be higher or lower than the approved number, depending on whether actual sales are higher or lower than the projected level. In this way, utility revenues and profits are a function of actual electricity sales, at least in the period between rate cases (which can sometimes be years). In most industries, this function would be normal and not a cause for concern, but in the electricity industry this pattern has led utilities to resist end-use energy saving efforts because they reduce sales.[43]

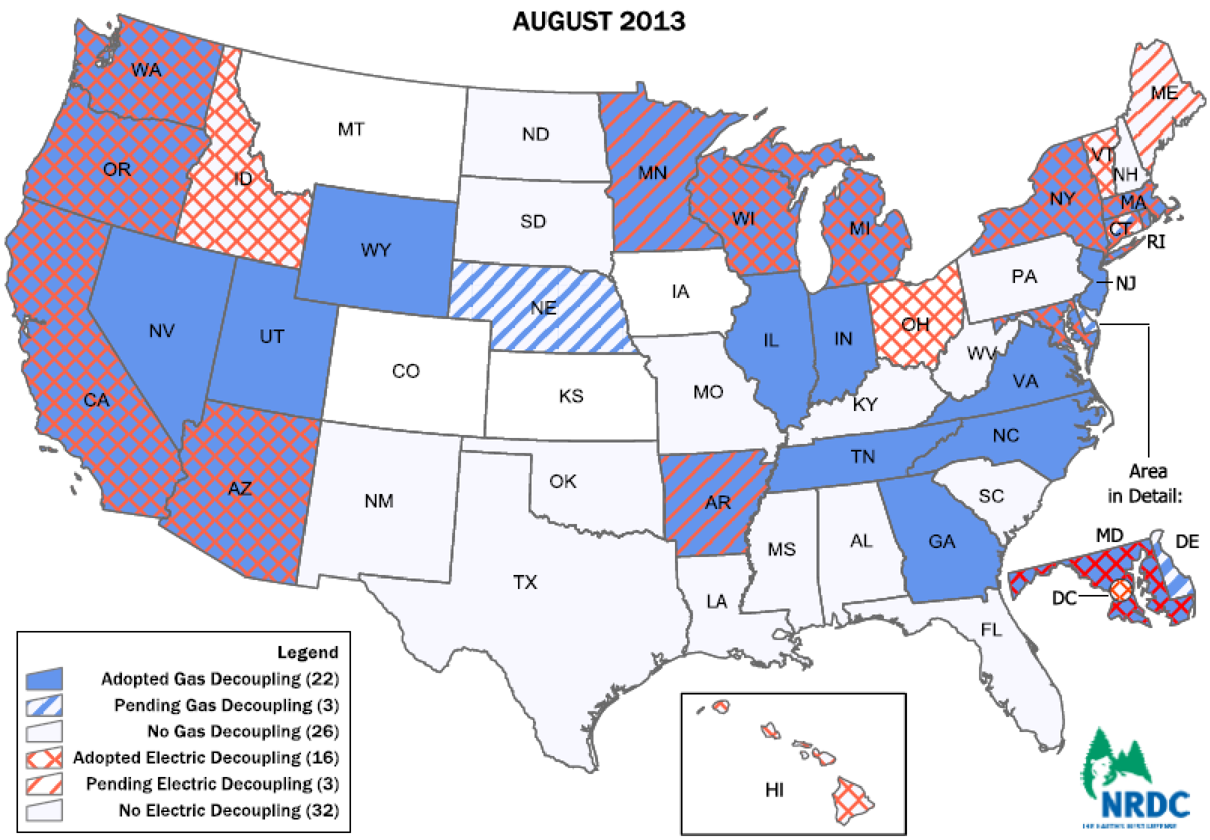
Beginning in the late 1980s, various states made changes to the traditional approach in order to remedy these incentives to resist energy efficiency. This became particularly important as states began to develop utility-delivered energy efficiency programs (see section 2.2). Broadly speaking, these states now employ two types of mechanisms, sometimes both at once. First, **decoupling** mechanisms break the link between profits and energy sales.[44] The periodic rate case review of utility costs and calculation of approved revenues remains similar to before decoupling. The difference is that retail prices are adjusted up or down between reviews (in a more or less automatic fashion, according to a set formula) to keep the utility's revenue at the approved level. Under a decoupling mechanism, reductions in demand due to end-use energy savings that occur between reviews no longer affect utility earnings.

But decoupling only removes disincentives toward energy efficiency; it does not motivate the utility to invest in energy efficiency as a resource. This is where the second type of incentive mechanism comes in: specifically, **financial incentives** to *encourage* utilities to invest in end-use energy efficiency. Some state regulatory commissions have implemented mechanisms that provide financial rewards when the utility meets specified targets for promoting end-use energy efficiency. Most of these are based on the "shared savings" concept, allocating a portion of the net consumer savings from energy efficiency to the electric utility as a reward for operating a high-performing program.

Colorado's Shared Savings Incentive offers an example of one state's approach to this type of program.[45] A 2007 Colorado law directed the state Public Utilities Commission to offer utilities an opportunity to make demand-side management investments more profitable than other investments. The bill also set a target that by 2018, energy savings in aggregate must reach at least 5 percent of 2006 energy sales.

[42] In the United States, "approved investment" is often called the "rate base."
[43] There are other important criticisms of the incentive effects of the traditional approach, including: 1) the traditional approach will give profit-maximizing utilities incentive to overinvest (i.e., push for higher approved investment), if the approved rate of return is higher than the firm's actual cost of capital; and 2) the utility may be inattentive to controlling operating expenses, to the extent these expenses are quickly approved and passed on to consumers.
[44] RAP, 2011.
[45] Partnership for Climate Action, 2010.

Figure 8: Decoupling Mechanisms in the United States



Source: NRDC, http://www.nrdc.org/energy/decoupling

Under the commission-approved approach for Public Service of Colorado, the utility earns an incentive if it achieves at least 80 percent of the adopted energy efficiency goal. The incentive is equal to 0.2 percent of net economic benefits for each 1 percent of savings beyond 80 percent of the goal, with the incentive increasing incrementally to 10 percent of net benefits at 130 percent of goal attainment. (If the utility achieves 100 percent of the goal, it earns an incentive equal to 4 percent of net economic benefits.) The utility earns 0.1 percent of net economic benefits for each 1 percent savings beyond 130 percent, and up to 12 percent of benefits at 150 percent of goal attainment.

The utility also receives a $2 million "disincentive offset" on an after-tax basis each year it implements an approved demand-side management plan – a step toward, but short of, decoupling. The performance incentive plus the disincentive offset cannot exceed 20 percent of total demand-side management expenditures. There are no penalties for failure to meet energy efficiency goals.

In 2006, CPUC established a three-part mechanism to encourage investment in energy efficiency in California. The first was a cost-recovery mechanism, funded through a system benefits charge to all electricity consumers. The second was a revenue regulation (decoupling) mechanism that recaptured net lost distribution revenues when sales declined. The third was a shared savings mechanism to give utilities a portion of the net energy value that the energy efficiency savings produced for customers.

The current version of California's shared savings mechanism, called the "risk/return incentive mechanism" (RRIM) is designed to align ratepayer and shareholder interests by creating a significant reward/penalty for IOUs' success or failure in meeting the CPUC's targets for reducing customer demand for electricity and natural gas.[46]

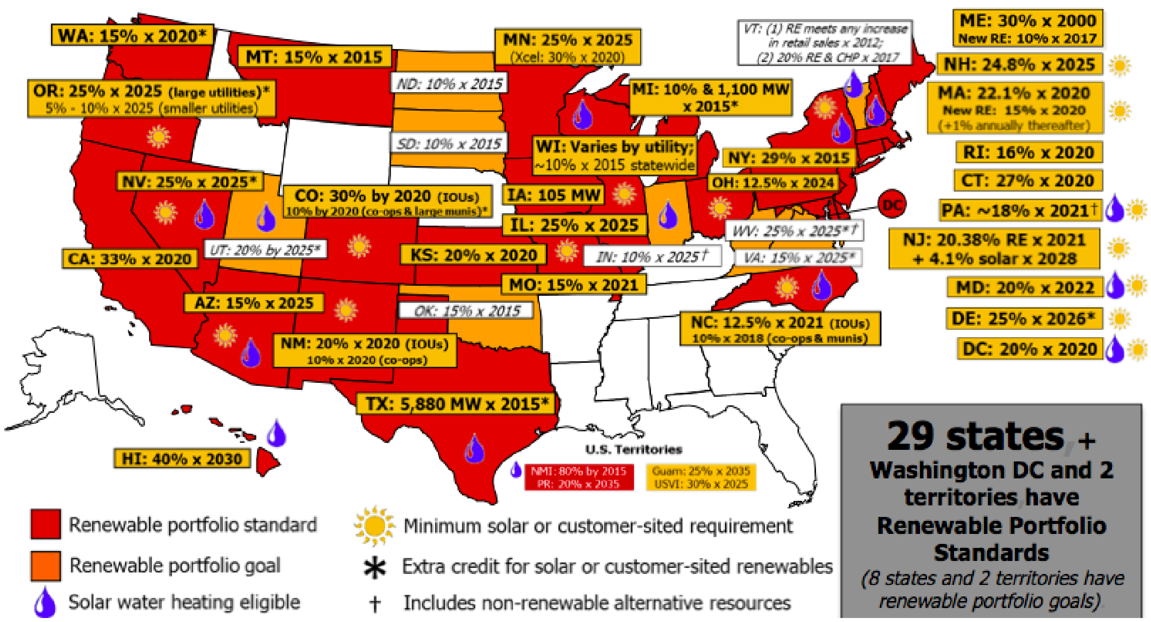
The RRIM is calculated for each investor-owned utility based on how well it meets the energy saving targets and the economic benefits generated from its energy efficiency portfolio. IOUs are eligible for the RRIM if they achieve 80 to 85 percent of CPUC energy saving targets and can earn greater incentives if they exceed the targets. Penalties may be triggered if savings are below 65 percent of the CPUC energy saving targets. For the 2006–2008 program cycle, total potential incentives were capped at $450 million (less than one percent of total revenues) for the four utilities combined. Two interim payments are provided, first after verifying actual energy efficiency measures installed and program costs, then after evaluation, measurement, and verification (EM&V) reports document projected per-measure savings. Thirty percent of the total incentive is held back pending a final post-installation EM&V "true-up."[47] While this incentive has been controversial, the CPUC has ruled in favor of providing significant rewards to the utilities, and the program performance has remained strong.

2.5 Renewable Energy Resources: Acquisition, Pricing, and Funding

Different US states have established different frameworks to acquire and fund renewable resources in a cost-effective, timely, and reliable manner. The most common form is the renewable portfolio standard (RPS), the use of which has been adopted by 29 states, as well as the District of Columbia and Puerto Rico.[48] (The California RPS is described further below.) Another seven states and two territories maintain nonbinding renewable energy goals.[49] See Figure 9. RPS policies require electricity suppliers to provide a minimum percentage or amount of their retail load with eligible sources of renewable energy generation or capacity. The policies are usually backed by penalties or alternative compliance payments. Renewable energy credits, with a credit equal to 1 MWh of eligible renewable energy generation that can be traded or transacted among market participants, are often part of state RPS policies. That said, no two state RPS policies are the same. There are numerous differences, encompassing eligible technologies, required level of renewables, who the RPS applies to, treatment of out-of-state generators, enforcement mechanisms, whether there are cost caps, the treatment of multi-fuel generation, and flexibility measures in complying with the RPS. Also, depending on the state, energy saved through efficiency measures sometimes counts towards meeting the portfolio standard.

[46] CPUC, 2007.
[47] CPUC, 2007.
[48] Barbose, G. (2014, September 22). *Renewables Portfolio Standards in the United States: A Status Update.* Presentation at the National Summit on RPS, Clean Energy States Alliance, Washington, DC. Retrieved from http://www.cesa.org/assets/Uploads/Barbose.pdf.
[49] REN21 (2014). *Renewables 2013 Global Status Report*. Retrieved from http://www.ren21.net/REN21Activities/GlobalStatusReport.aspx. Worldwide, 22 countries have adopted RPS or "quota" policies.

Figure 9: Renewable Portfolio Standards in the United States



Source: Database of State Incentives for Renewable Energy (DSIRE): http://dsireusa.org/summarymaps/index.cfm?ee=0&RE=0.

Renewable purchasing requirements such as the RPS are often highly detailed, complex policies with multiple tiers of eligible technologies, eligibility conditions (e.g., biomass fuels that meet source and emissions requirements), provisions on when (or if) penalties apply, and more. To limit rate effects, states have implemented several cost cap designs, such as alternative compliance payments (making a payment, usually in $/MWh of the shortfall, in lieu of procuring the requisite quantity of renewable generation or certificates), caps on allowable retail rate impacts, rate caps for particular classes of customers, caps on allowable renewable energy contract prices, and financial penalties that also serve as cost caps.

Overall, the aggregate trends are encouraging. State RPS policies have helped stimulate 51 GW of non-hydro renewable energy generation installed between 1998 and 2013 located in states with RPS policies. According to analysis by researchers at US national energy laboratories, by 2035, state RPS policies will stimulate 98 GW of new renewable energy capacity if full compliance is achieved. Furthermore, solar and distributed generation set-asides in 18 state RPS policies (including the District of Columbia) have driven 37 percent of US photovoltaic (PV) capacity additions between 2010 and 2012.[50]

State RPS policies must be carefully designed and implemented to achieve the desired result of adding more renewable energy capacity. Some common characteristics of successful state RPS policies include the following:

- *Broad Applicability* to all load-serving entities in a state, confirming that all customers who benefit from a RPS contribute equally towards meeting the cost.

[50] Barbose, 2014.

- *Balanced Supply and Demand* to ensure that it is large enough and binding enough to result in incremental renewable energy generation, without being so onerous as to foreclose RPS compliance.
- *Sufficient Duration and Stability* for the RPS to allow for long-term contracting and financing and for the RPS requirements not to shift or change suddenly and frequently over time. This has been an issue in several states where officials have repeatedly changed RPS target and eligibility requirement provisions. Opponents have also challenged RPS policies in many states, seeking to weaken or repeal them.
- *Well-Defined Resource Eligibility Rules* to avoid ambiguity of what resources and technologies are eligible for the RPS, thereby avoiding market uncertainty and instability.
- *Well-Defined Eligibility Requirements on Out-of-State Resources* to minimize the potential for solely meeting state RPS requirements with existing out-of-state renewable resources but also to avert any potential legal challenges under the Interstate Commerce Clause of the US Constitution.
- *Credible Enforcement* to ensure that RPS requirements will be met and to give financiers confidence in investing in new renewable energy projects.
- *Flexible Verification Measures*, such as certificate tracking systems, to minimize the cost of complying with a state RPS.
- *Adequate Compliance Flexibility*, such as allowing banking of renewable energy generation or certificates, helps overcome unpredictable supply and demand market conditions and minimizes RPS compliance costs.
- *Long-Term Contracting Requirements*, because renewable energy generation is capital-intensive and long-term contracts allow capital costs to be spread over a longer time period, lowering costs.[51]

The California Renewable Portfolio Standard is one of the most ambitious in the United States. The standard was first created in 2002, and applies to both investor-owned and consumer-owned utilities. The standard was subsequently amended by statute to meet a target of 33 percent by 2020. Interim targets of 20 percent and 25 percent were established for 2013 and 2016. The standard has proven achievable with 22.7 percent of generation being met through renewables in 2013, above the target of 20 percent.[52]

Tradable renewable energy credits may be used for compliance. In order to address the accounting issue related to the program, California participates in the Western Renewables Generation Information System.[53] State law also allows the regulator (CPUC) to require purchases above the statutory standard of 33 percent. (California has two regulators with jurisdiction, the other being the California Energy Commission.) Other roles of the regulator include the following:

- Certify eligible renewable resources that would be credited toward the standard.
- Establish a tracking and verification standard.
- Establish enforcement procedures.
- Refer non-compliant utilities to the California Air Resources Board for penalties.
- Review eligible contracts for potential rate recovery.

[51] See Wiser, R., Porter, K., Grace, R., and Kappel, C. (2004). *Evaluating State Renewable Portfolio Standards.* Retrieved from http://emp.lbl.gov/publications/evaluating-experience-renewables-portfolio-standards-united-states.

[52] See http://www.cpuc.ca.gov/PUC/energy/Renewables/.

[53] See http://www.wecc.biz/WREGIS/Pages/default.aspx.

- Establish standard terms and conditions for contracts.
- Establishing rules over compliance.
- Review and approve utility compliance plans.[54]

2.6 Renewable Energy Integration

Several US states, notably California, Iowa, Minnesota, and Texas, have significant amounts of wind power in the generation mix and are gaining valuable experience in integrating variable generation (VG). Strategies include implementation of VG forecasting, extraction of flexibility out of existing generation, recognition of need for new transmission, enlarging balancing areas, demand response, and energy storage. Faster scheduling and dispatch is also an important issue for renewable energy integration and will be discussed in the following section.

In June 2012, FERC issued Order No. 764, which is intended to remove barriers to the integration of VG. It requires transmission providers to offer intra-hourly transmission scheduling as an option for their customers. It also requires new interconnection requests from large variable generators to provide meteorological and forced outage data to their transmission utility, if the utility undertakes VG forecasting.

Implementation of VG forecasting: Forecasting is universally cited as a critical tool for integrating variable generation. All of the US regional transmission organizations (RTOs), and at least a dozen utilities in the Western United States, use it.[55] In addition, US RTOs are deploying near-term VG persistence forecasts of two hours or less to schedule and dispatch wind. Persistence forecasts, where the forecast simply echoes current VG production, are generally quite accurate.[56]

Extraction of flexibility out of existing generation: Iberdrola Renewables in the Pacific Northwest retrofitted an existing thermal plant to follow their wind fleet. The California Independent System Operator (CAISO) has proposed revising capacity reserve requirements to be based not just on resource adequacy (whether there is enough generation or demand response to meet electricity demand) but also on flexibility. In addition, both the CAISO and Midwest Independent System Operator (MISO) are pursuing flexibility ramp services.

Recognition of need for new transmission: The best VG resources tend to be in areas far from the cities or regions that have the highest electric demand, and thus require new transmission. Although a large up-front capital investment is required, accessing the lower operating costs of VG and providing more generation competition generally results in lower system costs.

One of the most significant transmission undertakings devoted to wind power, the Competitive Renewable Energy Zones (CREZ) project in Texas, was largely finished by the end of 2013. The Texas

[54] See Database of State Incentives for Renewables & Efficiency at http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=CA25R&re=1&ee=0.

[55] Widiss, R., and Porter, K. (2014, March). *Review of Variable Generation Forecasting in the West*, National Renewable Energy Laboratory. Retrieved from http://nrelpubs.nrel.gov/Webtop/ws/nich/www/public/Record?rpp=25&upp=0&m=1&w=NATIVE%28%27AUTHOR+ph+words+%27%27porter%27%27%27%29&order=native%28%27pubyear%2FDescend%27%29.

[56] Ahlstrom, M., et al. (2013). Knowledge is Power, *IEEE Power and Energy Magazine*, November/December 2013. Retrieved from http://ieeexplore.ieee.org/xpl/articleDetails.jsp?arnumber=6636012.

Public Utilities Commission convened a regulatory process that, with stakeholder involvement, selected zones with high renewable energy potential to connect with new transmission. The CREZ includes almost 3,600 circuit miles of transmission lines and will accommodate up to 18,500 MW of wind power. The $6.8 billion cost of CREZ was $2 billion higher than first estimated, in part because more than 600 circuit miles of additional transmission lines were needed to accommodate requested changes in routing from landowners. Because of CREZ, the Electric Reliability Council of Texas (ERCOT) reports that wind-related congestion between West Texas and other zones has largely disappeared. Transmission between the West and North hubs was the most congested in 2011 and third highest in 2012, but is no longer in the top 30.[57] At least in part because of the CREZ project, ERCOT projects that more than 7 GW of new wind capacity will be installed in Texas by the end of 2015, with another 1,318 MW projected to come online in 2016.[58]

As more VG is added to the grid, variable generation integration studies are examining the feasibility of integrating much higher levels, with transmission playing a critical role. The National Renewable Energy Laboratory (NREL) released a report in 2012 assessing the technical feasibility and the economic cost of incorporating VG at various penetration levels, from 30 percent to 90 percent, by 2050, with a particular focus on an 80 percent level. The report found that:

- Renewable electric generation technologies that are commercially available today, in combination with a more flexible system, is sufficient to meet 80 percent of US electricity demand for every hour and in every region of the country.
- Increased system flexibility through grid storage, demand response, flexible conventional generation, new transmission and changes in grid operations will be required.
- There is an incremental cost impact of an 80 percent scenario that is not fully offset by cost savings from reductions in fossil fuel consumption, as compared to continued operation and evolution of conventional generation. Improvements in renewable energy technology cost and performance will have the greatest impact on the incremental cost of high penetration of renewable generation.[59]

In 2013, the Minnesota Legislature required a renewable energy integration study to be released by November 2014 that would consider the technical feasibility of increasing the state's RPS to 40 percent by 2030 and to higher levels thereafter. The statute directs that the study include a conceptual transmission plan for delivering VG and to identify and consider possible solutions to any critical problems that are found. A team of the Minnesota utilities, MISO, Excel Engineering, and GE Energy Consulting are preparing the study under the direction of the Minnesota Department of Commerce's Division of Energy Resources. The Minnesota PUC ordered all utilities in the state to participate in the study.[60]

Enlarging balancing areas: Regulatory agencies, policymakers, and other stakeholders have been working to enlarge balancing areas, particularly in the southern and western parts of the US, where balancing areas have historically been relatively small. Larger balancing areas have several advantages.

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[57] Micek, K. (2014). Texas CREZ Program Eases Wind Congestion, *Megawatt Daily*, January 21, 2014.

[58] Carr, H. (2014). ERCOT Sees 7,000 MW of New Wind by End of 2015, *Megawatt Daily*, May 5, 2014.

[59] Hand, M.M., Baldwin, S., DeMeo, E., Reilly, J.M.; Mai, T.; Arent, D.; Porro, G.; Meshek, M.; and Sandor, D (2012). *Renewable Electricity Futures Study*, National Renewable Energy Laboratory. Retrieved from http://www.nrel.gov/analysis/re_futures/.

[60] Minnesota Department of Commerce. *Minnesota Renewable Energy Integration and Transmission Study*. Retrieved from http://mn.gov/commerce/energy/topics/resources/energy-legislation-initiatives/studies-and-reports/minnesota-renewable-energy-integration-transmission-study.jsp.

First, they reduce the variability of load. Second, they reduce the variability of wind generation and solar generation. Third, larger balancing areas allow access to a larger pool of generation for balancing and for reserves. Fourth, reducing the variability means less reserves are needed. Finally, VG forecasting errors can also be reduced: one study showed error reductions of 30 to 50 percent by aggregating multiple wind plants across a balancing area (as compared to wind forecast errors of individual or geographically concentrated plants).[61]

A NREL-GE study assessed the feasibility of integrating larger amounts of wind and solar in the western U.S. and found that modeling the Western U.S. as five large regions instead of the current (approximately) three dozen balancing authorities would save $1.7 billion (2009 dollars) in lower requirements for reserves.[62] MISO says that annual benefits from a larger balancing area amount to between $2.1 billion and $3 billion in economic benefits in 2013 through improved dispatch and the reduced need for ancillary services, among other things.[63]

Expanding balancing areas can be accomplished either by physically combining balancing areas into a single balancing area, or virtually through sharing reserves or energy imbalances. The Southwest Power Pool (SPP) first used the virtual consolidation approach, implementing a voluntary energy imbalance market in 2007. In March 2014, SPP physically consolidated into one balancing area. The virtual consolidation approach has also been gaining support in the US West. The California ISO and Pacificorp, a utility that serves six Western states, will launch an energy imbalance market in November 2014. NV Energy of Nevada will join in October 2015.

Demand response: Demand response is increasingly recognized by policymakers and regulatory agencies as an important and economical resource for grid operators. Demand response programs are growing rapidly: for example, among the seven RTOs in the country, FERC found that demand response contributed 28 GW, or about 6 percent of peak demand, in 2012.[64] The North American Electric Reliability Council (NERC) projects that demand response will grow by another 3.3 GW by 2023, with energy efficiency growing by 11.9 GW over that same period. Nationwide, NERC found that demand response contributed 3.8 percent to total annual demand on average.[65]

Major challenges remain in designing demand response programs to support renewable energy integration.[66]

[61] See Lew, 2011. In addition, to cite a European example, Holttinen (2012) found that combining the balancing areas of Eastern and Western Denmark added about 100 km and resulted in the total canceling out of day-ahead wind forecast errors at least one-third of the time.

[62] See GE Energy (2010, May), *Western Wind and Solar Integration Study*, prepared for the National Renewable Energy Laboratory. Retrieved from http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf.

[63] See Midcontinent Independent System Operator (2014, February), *2013 Value Proposition.* Retrieved from https://www.misoenergy.org/Library/Repository/Communication%20Material/Value%20Proposition/2013VP/ValueProposition_2013.pdf.

[64] See Federal Energy Regulatory Commission (2013, October), *Assessment of Demand Response & Advanced Metering* [Staff Report]. Retrieved from http://www.ferc.gov/legal/staff-reports/2013/oct-demand-response.pdf.

[65] See North American Electric Reliability Corporation (2013, December), *2013 Long-Term Reliability Assessment*. Retrieved from http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_FINAL.pdf.

[66] P. Cappers, A. Mills, C. Goldman, R. Wiser and J. Eto (2011, October). *Mass Market Demand Response and Variable Generation Integration Issues: A Scoping Study,* Lawrence Berkeley National Laboratory. Retrieved from http://eetd.lbl.gov/ea/ems/reports/lbnl-5063e.pdf.

- Variable time-based retail rates, such as real-time pricing, combined with customer automation and controls, have large potential to support variable generation integration.
- Retail market tariffs often do not allow utilities or aggregators to compensate retail customers who participate in demand response programs.
- Load aggregators facilitate participation of residential and small commercial users, but policies to support entry of load aggregators are not yet widespread in the United States.
- Reliability rules in many areas need to be adjusted in order to allow aggregators or large customers to provide demand response services. Expanding wholesale market product definitions and market rules to allow demand response to offer (and be paid for) providing services to integrate variable energy generation would also be beneficial.

Demand response can also involve increasing energy consumption at a time of high levels of VG that cannot be managed by the grid operator absent curtailment. This approach primarily uses thermal energy storage to allow the timing of electricity delivery to be decoupled from the delivery of the associated energy service. An example is electric water heaters, where surplus electricity can be used to heat water above normal set points, to be mixed later with colder water to deliver the same quality and quantity of energy services (in this case, hot water) without interruption. An example is a pilot of Mason County Public Utility District #3, in Washington, which is testing a technology that uses water heaters for 100 customers to store energy when variable generators are producing power, while delivering steady hot water service to the customer.[67]

Energy storage: Energy storage consists of a mix of old (pumped storage hydropower) and new technologies (batteries, flywheels, and compressed air energy storage systems) and offers a diverse set of benefits to the grid. These include displacing alternative investments in distribution, transmission and generation; providing ancillary services at a faster speed and more precisely than conventional generation; and adding resiliency and greater reliability to the grid, particularly in areas that are subject to power quality disturbances and outages. Storage can also support integration of VG, but so far, energy storage is not as competitive in the United States as other options for integrating VG, such as flexible natural gas or hydro plants.

The United States has about 25 GW of storage facilities, with pumped storage hydropower plants accounting for more than 95 percent of the installed capacity. Pumped storage hydropower plants are used mostly for shifting the time of generation to take advantage of the difference in prices between off-peak and on-peak. The remaining 5 percent consist of thermal storage, compressed air, batteries, and flywheels.

Improving technical performance and increasing cost competitiveness are sparking several initiatives concerning energy storage. About 200 energy storage demonstration projects are in progress in the United States, with hundreds more in the planning and development stage. More than 2 GW of RFPs for utility-scale storage have been issued. Energy storage also is an eligible technology for RPS policies in eight states and Puerto Rico. Finally, California is requiring its investor-owned utilities to procure 1.3 GW of energy storage by 2020, and publicly owned utilities to adopt energy storage targets if it is cost-effective.

[67] L. Schwartz, K. Porter, C. Mudd, S. Fink, J. Rogers, L. Bird, M. Hogan, D. Lamont, and B. Kirby (2012, May). *Meeting Renewable Energy Targets at Least Cost: The Integration Challenge*. Retrieved from http://www.raponline.org/featured-work/meeting-renewable-energy-targets-in-the-west-at-least-cost-the-integration.

A challenge for energy storage is that it generates multiple benefits that are not always monetized in either wholesale or retail markets. These include energy arbitrage, balancing services, capacity value, deferral of distribution system equipment, and mitigation of service outages. In addition, individual storage technologies differ by maturity and commercial readiness. Finally, because many energy storage technologies are relatively new, regulatory officials involved with environmental, construction, electricity, and fire codes and regulations have safety and reliability concerns.[68] Those concerns are not unusual for newer technologies—solar faced some of these same issues—and they can be eased with increased experience with energy storage installations.

2.7 Generator Dispatch

Like the other two regions discussed in this paper, in the United States the object of dispatch is to optimize the use of the available capacity, which is to say meet load at the lowest total operating cost.[69] Generally speaking, this is achieved when operations are determined by marginal (variable) cost, known as a merit order ranking. In this regard, there is no difference in principle between the states that have "restructured" (including adoption of wholesale markets) and states that have not, although there are some differences in method.[70]

First, consider states that have not restructured. Where the balancing area consists of only one vertically integrated utility, dispatch is typically managed by that utility. Where there are multiple utilities and dispersed ownership of generation resources, the resources are "pooled" (shared) and dispatch is typically managed by a third party (system operator), established for the duty. In both cases, dispatch is done according to estimates of variable costs.

In regions that have restructured and there are competitive wholesale energy markets, dispatch is done according to bid prices. The basic logic is that in a well-designed system, the bids will typically reflect each generator's variable operating costs. In what are called "day-ahead" markets, suppliers (who may or may not own generation) bid the quantities and prices of electricity that they are willing to supply in specified hours of the following day. Those bids are "stacked" (lowest to highest) against the expected levels of demand in those hours and cleared at the price of the highest bid necessary to meet the demand.[71] The results of these auctions determine the dispatch for the following day.[72] All producers

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[68] T. Stanton, *Envisioning State Regulatory Roles in the Provision of Energy Storage*, National Regulatory Research Institute, 2014, http://energystorage.org/system/files/resources/nrri_14-08_energy_storage.pdf.

[69] Generator dispatch is a broad topic. The purpose of this section – as well as the discussions of generator dispatch in other regions, below – is to highlight some basic issues that should be of particular importance to readers in China. Due to space constraints, we omit discussion of many important issues, technical details, and current topics of debate in the United States.

[70] It's important to note that, though merit order dispatch, however achieved, will minimize the total system's total operating costs, it would be wrong to assert, absent the full internalization of external (mostly environmental damage) costs, that this dispatch is most economically efficient. So long as some costs, such as poor air, land, and water pollution, climate change, and decreased public health are not in some manner valued and recognized in dispatch (and, in the longer run, investment) decisions, economic efficiency, in its proper and most ecumenical sense, will not be realized.

[71] Demand in each hour is determined in one of a couple of ways. In some markets, the demand curve is determined administratively, usually by the system operator. Other markets enable buyers to bid how much and at what price they are willing to purchase in those hours. These bids are then "stacked" (highest to lowest) and compared to the supply bids. Where the demand curves (the supply and demand bid "stacks") cross each other, the market clears (some minor adjustments to total volumes are generally necessary, which is possible because the market rules call for the bids to be made in discrete amounts or "blocks," e.g., 25 MW at $YY in Hour XX. A buyer or seller can bid as many blocks as it wants, at the same or at different prices.

whose bids are less than or equal to the clearing price will be dispatched and paid the clearing price. It is important to note that, as wholesale markets evolve to provide a greater variety of capabilities (in particular, operational flexibility to support increased penetration of variable renewable resources), differentiated product markets and bidding strategies are emerging that add new layers of complexity to the story. The essential message, however, remains unchanged: The objective of the market is to produce the economically efficient, least-cost operation of the system.

Faster scheduling and dispatch has been important for renewable integration. In the Western and Southeastern United States, dispatch and transmission schedules are set hourly. Because changes are allowed only for unanticipated events, changes in electricity demand within the hour cannot be met with changes in schedule. Therefore, transmission providers must carry enough reserves to cover the largest potential contingency during that hour, even if it is only for a short period of time. Intra-hour transmission scheduling would allow transmission providers to change schedules to better match load and hold lower amounts of reserves during the hour. FERC recently ordered transmission providers to offer, but not require, sub-hourly scheduling.

In contrast, some US RTOs dispatch at five-minute intervals, enabling other available generators that can economically respond to do so. This significantly reduces movements of generating plants and makes grid operation more efficient. Xcel Energy reports that in its balancing authority area in the Midwest ISO, wind increased from 400 MW to 1,200 MW without any change in the utility's flexibility reserves or regulation requirements because of five-minute dispatch.[73] Integration studies have found lower costs in areas with faster dispatch. Integration costs in studies for RTO areas with five or 10 minute dispatch ranged from zero to about $4 per megawatt-hour (MWh), while areas with hourly dispatch had integration costs of about $8 to $9 per MWh.[74]

2.8 Carbon Trading and Pricing

Despite detailed proposed national legislation debated in the US Congress, there is no national carbon pricing scheme in the US. However, a number of states have implemented carbon cap-and-trade (also known as "emission trading") schemes. These schemes are having significant effects on power sector emissions in these states. The Regional Greenhouse Gas Initiative (RGGI), consisting of nine states in the northeastern US, and California have established carbon emissions trading schemes. RGGI is a particularly useful example of the interactions between carbon trading and power sector regulation and is the focus of this section.

RGGI, launched in January 2009, caps aggregate carbon emissions from all power plants larger than 25MW in its nine-state region.[75] These states developed a pioneering and effective emissions trading model in which the state governments auction emission allowances (rather than giving them away for free) and then use the revenue to fund energy efficiency programs (mostly run by utilities; see section

[72] There will be, in many cases, a series of follow-on auctions that enable participants to refine their positions in the market, as well as auctions or other procedures to procure various ancillary services. There is also a "day-of" real-time market that allows for further arbitrage and deals with imbalances. The essential point, however, remains: namely, that bid prices determine dispatch.

[73] Communication with Stephen Beuning, Xcel Energy, April 16, 2012.

[74] ISO/RTO Council, 2007.

[75] The members of RGGI are Connecticut, Delaware, Massachusetts, Maryland, Maine, New Hampshire, New York, Rhode Island, and Vermont. Together, they account for more than 20 percent of US GDP. New Jersey withdrew from RGGI in 2011.

2.3 above).

The program is based upon provisions agreed to by the RGGI member states in a memorandum of understanding (MOU) signed in December 2005.[76] The RGGI MOU established a stable cap for electric sector CO_2 emissions of approximately 188 million short tons per year from 2009–2014. The cap was to then decline at a rate of 2.5 percent per year for four years from 2015–2018. This approach was intended to result in a 2018 annual emissions budget 10 percent lower than the initial 2009 budget.[77]

Unexpectedly slow economic growth, together with unexpectedly low natural gas prices (which pushed coal and oil out of the generation mix) together depressed emissions below the cap. The MOU requires a review of the program after five years of operation, which gave the states an opportunity to react to these changed circumstances: in 2014, they tightened the cap dramatically to 91 million short tons per year in 2014 with a declining trajectory of 2.5 percent per year over 2015– 2020.[78] This requirement to review and adjust is a strength of the scheme.

Only a small fraction of allowances are given to power plants for free. The rest have been sold at auctions, which are held quarterly. Despite low prices (sometimes at the “floor price” established in the MOU), this has raised substantial amounts of revenue. The total auction for the first four years of operation for the nine states was $984 million.[79] This amount is not large relative to the size of the population in the RGGI region (it equals an annual amount of about $6 per capita), although it is very significant compared to spending on energy efficiency. For comparison, per capita utility investment in energy efficiency was only about $11 (on average, across all US states) in 2009.[80] Emissions were below the cap during the first four years of operation, but the scheme still generated auction revenue because of a floor price on emissions. Auction revenues have recently begun to increase as a result of the tightening of the RGGI cap.

RGGI is the leading example of “recycling” ETS auction revenue into state and utility-run programs that investment in energy efficiency. Only about 10 percent of revenue goes to support the general state budgets; the rest is recycled into the RGGI program. In the first four years of RGGI operation, the breakdown for this recycled revenue is as follows:

- 65 percent went to state and utility programs to improve energy efficiency;
- 6 percent to deploy renewable energy resources;
- 6 percent to other GHG reduction programs;
- 17 percent to assist low-income households; and
- 6 percent to program administration.[81]

These percentages vary by state. Some RGGI states have enacted legislation setting a minimum percentage of revenue from auctions that must be spent on energy efficiency. Vermont requires that

[76] For more detail, see RGGI Program Overview: http://www.rggi.org/design/overview. The MOU and amendments are available at http://www.rggi.org/design/history/mou.
[77] RGGI’s initial regional cap of 188 million short tons of CO_2 per year was approximately 4 percent above annual average regional emissions during the period 2000–2004.
[78] See RGGI (2012), *Program Review: Summary of Recommendations to Accompany Model Rule Amendments*. Retrieved from http://www.rggi.org/docs/ProgramReview/_FinalProgramReviewMaterials/Recommendations_Summary.pdf.
[79] RGGI, 2014.
[80] Lazar, 2011.
[81] RGGI, 2014.

100 percent of proceeds be spent on energy efficiency.

RGGI's revenue recycling has effectively targeted low-cost energy efficiency resources while reducing average consumer electricity bills.[82] From 2014 forward, given the newly tightened cap, RGGI should generate more revenue, which in turn will continue to support energy efficiency.

2.9 Current Issues and Concluding Comments

Current policy discussions in the United States center on the EPA's proposed *Clean Power Plan*, issued in June 2014.[83] Because of opposition in the US Congress to enacting legislation to limit greenhouse gas emissions, EPA used its existing regulatory authority under the Clean Air Act to put forth this proposal. The EPA expects the plan will decrease carbon dioxide emissions from the power sector 30 percent below 2005 levels by 2030. The plan is an important step forward, although it is likely that significantly larger emissions cuts could be achieved cost-effectively over the same period.

Under the proposal, EPA will establish binding state-specific emissions reduction targets. Each state will be allowed flexibility in developing plans to meet the target; EPA will be responsible for reviewing and approving (or disapproving) the state plans. EPA encourages states to base their efforts on existing state planning procedures. Most states already practice some form of integrated resource planning for electricity supply that seeks to find the least-cost resource mix (including energy efficiency) and considers the costs associated with various emissions.

The state targets are set in terms of carbon emissions intensity (i.e., pounds of carbon emissions per MWh), and EPA has developed a methodology that allows a variety of control measures to count toward intensity reductions. In other words, the plan allows several approaches that states can use to meet their targets. Each state will be able to put together a cost-effective (or least-cost) mix of resources including:

1. **End-use energy efficiency:** The proposal encourages states to reduce power sector emissions by investing in end-use energy efficiency as a substitute for thermal power plants and explicitly recognizes such investments as effectively producing carbon-free kilowatt-hours. State plans can use verified savings achieved through state power sector energy efficiency programs (which, in most states, are administered by electric utilities and overseen by state regulatory agencies). This is very similar to China's energy efficiency power plant (EPP) concept — although EPA takes that concept a step forward by integrating EPPs into a detailed and transparent carbon-reduction power plan. EPA expects all states to be able to implement energy efficiency programs that achieve annual energy savings of at least 1.5 percent of annual sales. Several states already exceed this target.
2. **Renewable energy**: New investments in renewable energy can count toward state targets. EPA calculated that the percentage of generation supplied by renewables in each state could be ramped up, although wind and solar still supply less than 15 percent of electricity in EPA's 2030

[82] Hibbard, et. al., 2011; ENE, 2014; RGGI, 2014.
[83] The proposal and associated documents are available at www.epa.gov. This discussion is drawn from James and Dupuy, 2014.

scenario. Hydro generation can also count toward state targets, although EPA does not expect any major new construction, primarily because of the lack of availability of hydro sites.[84]

3. **Redispatch (changes to annual running hours across the fleet of power plants)**: This option reflects programs that dispatch gas plants more often and coal plants correspondingly less often. Available wind and solar resources are assumed to be given priority over thermal resources. EPA's plan calls for raising the average capacity factor of natural gas plants from 44–46 percent in 2012 to 70 percent in 2030.[85]

4. **Heat-rate improvements:** This category refers to efficiency increases *within* existing thermal power plants. EPA projects an average of 6 percent improvement across all plants.

5. **Nuclear energy:** Nuclear generation can also count toward the state targets, although EPA does not expect any significant new construction in this category through 2050 because of the high costs of building plants. EPA allows states some limited credit for keeping existing plants in operation.

EPA calculates that the benefits of the plan will far exceed its costs from a whole-society point of view. Costs will include investments in new renewable capacity and energy efficiency measures; benefits will include the climate and health effects of emission reductions, as well as the economic benefits of energy savings. Importantly, EPA calculates benefits not just from reduced carbon emissions (avoided climate change) but also from associated reductions in conventional pollutants (including reduced emissions of ozone precursors, fine particles, and mercury). These conventional emissions reductions are not the main focus of the program — but the benefits, particularly in terms of human health, are substantial and including them in the calculation of benefits (as well as considering them in program design) is good practice. In fact, the EPA calculations imply that even in the absence of any benefits stemming from climate change mitigation, the value of the public health benefits from air quality improvement alone (in the sense of total benefits exceeding total costs) would justify the proposed policy. Table 1 summarizes EPA's cost-benefit calculation associated with one of EPA's main scenarios.[86]

Total compliance costs reflect the total costs of implementing the proposed policy. Specifically, the compliance costs include the cost of redispatching away from coal toward gas and the cost of new renewable capacity. Compliance costs also include the cost of energy efficiency (both the costs borne by the program administrators and the program participants). However, EPA's calculations show that energy efficiency is much less expensive than other power sector resources and other emission-reduction options.

[84] Hydroelectric generation in the United States has remained constant for the past 20 years. However, many new pumped storage sites, totaling over 50 GW are being pursued in the US, and development of these will enable VG to serve an increasing share of total electricity requirements. See http://www.hydro.org/wp-content/uploads/2012/07/NHA_PumpedStorage_071212b1.pdf.

[85] EPA concludes that individual natural gas plants are capable of operating with utilization rates as high as 87-92 percent.

[86] See Table 2 of EPA (2014), *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, 79 FR 34829. Retrieved from https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.

Table 1: Cost-Benefit Analysis of Clean Power Plan Scenario

Climate benefits	$30 billion
Air pollution benefits (public health)	$27 to $63 billion
Total compliance costs	$8.8 billion
Net benefits	$49 to $84 billion

The timeline for the proposed rule is as follows:

- Until December 1, 2014: Detailed plan open for public comment.
- June 2015: The rule will be finalized and released.
- June 30, 2016: State compliance plans must be submitted to EPA.
- 2030: EPA's emission rate targets must be met.

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3. European Union

3.1 Institutions and Functions

The European Union (EU) is an economic and political union of 28 Member States that share common markets, policies, and regulations. The European Commission (EC), the EU's executive branch, exercises limited powers over member governments, but EU directives have an increasingly important influence over the orientation of national policy. In the power sector, there has been gradual movement toward an integrated, EU-wide electricity market with harmonized industry rules, though they are presently characterized by a patchwork of national regulatory frameworks, national and regional power exchanges, and national and regional companies.

In energy and environmental policy, EU directives have set national targets for renewable energy, energy efficiency, and GHG emissions, but allow Member States considerable autonomy in how these targets are achieved. Greater integration of electricity sectors across Member States will be critical for cost-effectively meeting EU environmental goals, because of the diversity of energy resources across the EU. The EU has committed to a "2020 climate and energy package," including 1) a legally binding target of reducing GHG emissions 20 percent below 1990 levels, with specified financial penalties for failure to comply; 2) a legally binding target to raise the share of EU final energy consumption produced from renewable resources to 20 percent;[87] and 3) a non-binding target for 20 percent improvement in the EU's energy efficiency. In October 2014, the EU leaders agreed to a 2030 framework that includes a target to reduce emissions 40 percent below 1990 levels. For 2050, EU leaders have announced a commitment to cut economy-wide emissions by 80–95 percent compared to 1990 levels and has published a 2050 roadmap in support of that commitment.[88]

Since the late 1990s, the EU has worked to harmonize industry structure and create the foundations for an EU-wide internal market in electricity. EU directives require all Member States to: create competitive wholesale markets for generation; open the electricity retail sector to competition and liberalize retail prices; unbundle transmission, distribution, and generation; ensure non-discriminatory generator dispatch and provide non-discriminatory third-party access to the grid network through the creation of independent system operators; develop market mechanisms to allocate intertie capacity; and establish dedicated, independent regulators for the energy sector.[89] However, despite nearly two decades of effort, the EU internal market in electricity remains a work in progress. There is still significant variation among EU Member States in terms of: the competitiveness of wholesale and retail markets; market design and function; the extent of unbundling and non-discrimination; the degree of government involvement in the sector; and the independence and function of regulators.

EU Member States have experienced some degree of convergence in regulation and the roles and functions of regulators over the past decade. Historically, power sector regulation in many EU Member States was undertaken by government ministries. Driven by EU directives, national governments are

[87] The EC expects approximately 34 percent of final *electricity* consumption from renewable sources by 2020, including electricity from large hydroelectric facilities. See http://iet.jrc.ec.europa.eu/eu-track-2020-renewable-energy-targets.

[88] For detailed information on the 2020, 2030, and 2050 goals, along with the 2050 Roadmap and other supporting documents, see http://ec.europa.eu/clima/policies/brief/eu/index_en.htm.

[89] These requirements were formulated in three directives spanning 13 years: Directive 2009/72/EC in 2009, Directive 2003/54/EC in 2003, and Directive 96/92/EC in 1996. See also http://ec.europa.eu/energy/gas_electricity/legislation/third_legislative_package_en.htm.

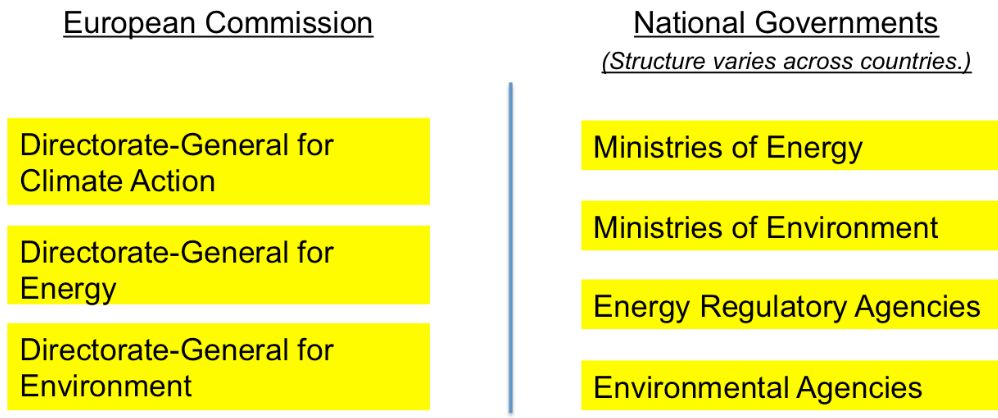
increasingly moving toward establishing dedicated energy regulatory agencies that are functionally independent from government. Key functions of these agencies often include: appointing system operators, approving investment plans, licensing for generators and transmission and distribution (T&D) facilities, market monitoring, ensuring non-discriminatory access, and tariff setting for T&D and, in some cases, retail prices. Although it is unlikely that the EU will have a common regulatory system or a single electricity regulator soon, the EC's Third Energy Package (Directive 2009/72/EC) proposed institutions to facilitate greater coordination among national regulators and further national cooperation on cross-border transmission. In particular, it led to the creation of the European Agency for the Cooperation of Energy Regulators (ACER) in 2010. ACER's mandate is to coordinate among national regulators, participate in the development of regional transmission infrastructure and rules, and monitor regional markets.[90]

Energy and climate policies within the EU include both EU directives and national and local policies and planning. Of direct relevance to the electricity sector, the EU has issued directives on renewable energy, energy efficiency, GHG emissions cap and trade, and SO_2, NO_x, and particulate matter (PM) emission standards.

- **Renewable Energy**. The Renewable Energy Directive (Directive 2009/28/EC) sets legally binding national targets for the share of renewable energy in each EU Member State's gross final energy consumption,[91] consistent with an EU-wide target of 20 percent in 2020. Each country must develop a National Renewable Energy Action Plan (NREAP) that establishes national targets for renewable energy in electricity, heating, cooling, and transport. Current NREAPs suggest that, on average, one-third of the electricity consumed in the EU will be generated from renewable sources by 2020.[92] In October 2014, the European Council endorsed a 2030 renewables target of 27 percent.[93]
- **Energy Efficiency**. The Energy Efficiency Directive (Directive 2012/27/EU), discussed in greater detail below, requires national governments to set targets for energy consumption and savings over 2014–2020.
- **GHG Emissions Cap and Trade**. Directive 2003/87/EC created the EU Emissions Trading System (EU-ETS), which established national caps on GHG emissions in select sectors, a system of national plans for allocating allowances, and a trading system for allowances. The third phase of the EU-ETS, which began in January 2013, introduced a single EU-wide cap on GHG emissions in capped sectors (21 percent below 2005 levels in 2020), expanded the sectors and gases included in the cap, and abandoned the system of national allowance allocation in favor of centralized allocation and a greater reliance on auctions to allocate allowances.
- **SO_2, NO_x, and PM Emissions Standards**. The Large Combustion Plant (LCP) Directive (Directive 2001/80/EC) requires new power plants larger than 50 MW to meet standards for SO_2, NO_x, and PM emissions. The LCP Directive requires existing power plants to meet emissions standards by 2008 or to choose to opt out. Plants that opt out are allowed to run for another 20,000 operating hours or until the end of 2015. An update to the LCP Directive in 2011, under the Industrial Emissions Directive (IED), tightens emissions standards for existing power plants.

[90] See ACER website at http://www.acer.europa.eu/Electricity/Pages/default.aspx.
[91] Gross final energy consumption is the energy delivered to end users, plus facility own-use and distribution losses for electricity and heat.
[92] European Renewable Energy Council (2011). *Mapping Renewable Energy Pathways towards 2020*, Brussels, Belgium.
[93] Bennett, P. (2014). EU sets 2030 renewable energy target of 27%, *PVTech*, October 24, 2014. Retrieved from http://www.pv-tech.org/news/eu_sets_2030_renewable_energy_target_of_27.

Figure 10: Key Institutions Active in the EU Power Sector



Several EU Member States have set nearer- and longer-term national targets for renewable energy, energy efficiency, and GHG emissions that are more aggressive and far-reaching than EU requirements. Germany's *Energiewende*, for instance, lays out a long-term plan for transitioning the country towards a renewable energy supply by 2050 and establishes more aggressive GHG abatement targets than those for which the country is obligated under EU legislation. The UK's 2008 Climate Change Act establishes long-term GHG targets and five-year budgets, as well as the supporting institutional infrastructure, for a transition to a low carbon economy by 2050. This includes a CO_2 emissions performance standard (EPS) for new fossil fuel units, set at 450 gCO_2/kWh, which is intended to ensure that no new coal units are built without the ability to capture and store carbon.[94]

3.2 Power Sector Structure

There remains a large degree of diversity across EU Member States in terms of power sector structure, although this is gradually diminishing under the EU's efforts described above. In some Member States, national companies still dominate all facets of the electricity industry, whereas in others ownership has diversified, generator dispatch and network access are now non-discriminatory, and retail competition is more developed. Figure 11 describes industry segments in the EU.

In most EU Member States, electricity suppliers either obtain the majority of energy needed to serve their customers through self-supply or from bilateral contracts.[95] National or regional power exchanges provide centralized day-ahead markets that allow electricity suppliers to purchase residual energy needs for the following day and intra-day markets that allow generators and suppliers to rebalance their energy market positions. Most wholesale markets in the EU are "energy-only," though a number of Member States have separate mechanisms to compensate generators for capacity or reserve capacity and still more are considering such mechanisms to ensure reliability (see *Supporting Resources*, below).[96] All EU Member States have some form of price cap on wholesale market bids.[97]

[94] For more on the EPS, see IEA (2012), *Energy Policies of IEA Countries: The United Kingdom 2012 Review*, Paris, France: OECD/IEA.

[95] See, for instance, Karas, J. and Sulamaa, P. (2013, June), *The Increasing Scope and Authority for Power Exchanges*, Elforsk AB Working Paper.

[96] Romania has a capacity market. Greece, Ireland, Portugal, and Spain all make separate capacity payments to generators. The UK and Italy are in the process of implementing annual auctions for capacity. Finland, Sweden, and Poland have a strategic

Figure 11: Power Industry Segments in the EU

Industry Segment				Representative Member States
G	**T**	**D**	**R**	
G	T	D-R		Czech Republic, France, Greece, Italy, Poland
G	T	D	R	Denmark, Germany, UK

Abbreviations: G=generation, T=transmission, D=distribution, R = retail

EU Member States agreed to a goal of creating an internal market in electricity, including integrated day-ahead and intra-day wholesale markets for generation, by 2014. Some degree of integration in day-ahead wholesale markets occurred over the 2000s and 2010s, through the bottom-up "coupling" of national power exchanges, but little progress has been made to date in the coupling of intra-day markets.[98] In coupled markets, generators bid into their national or regional market, and power exchanges then use available cross-border transmission capacity to minimize price differences between markets. Prices in national or regional markets converge when there is no cross-border transmission congestion, and diverge when there is. In February 2014, the four exchanges in the northwestern EU achieved a milestone by coupling day ahead markets across 15 Member States. In the same month, these exchanges announced plans to link intraday markets, in order to provide greater flexibility needed to cost-effectively balance intermittent wind and solar energy across the EU footprint.[99]

3.3 Power Sector Planning

EU Member States will face significant transition challenges in the next decade, as power sectors are transformed from national balancing areas dominated by coal- and gas-fired power plants to an EU-wide grid with a diverse generation mix that includes significant amounts of variable generation. Wholesale and retail markets are central to the EU's vision for achieving this transformation. This will require planning by policymakers and regulators to identify desired outcomes and realistic goals (e.g., for renewable energy), and will also require careful design of market mechanisms to achieve these outcomes and goals.

reserve mechanism, in which the TSO procures capacity for use in emergency situations. See Hall, S. (2014), EU electricity market capacity mechanisms "unavoidable," *Platts*, 19 February 2014, retrieved from http://www.platts.com/news-feature/2014/electricpower/eu-electricity-capacity-mechanisms/index.

[97] EC (2013, May 11). *Generation adequacy in the internal electricity market - guidance on public interventions.* Commission Staff Working Document.

[98] The Belgian, French, and Dutch day-ahead markets were coupled in 2006. The Benelux countries, France, and Germany were coupled in 2010. See European Power Exchange website: https://www.epexspot.com/en/market-coupling/another_step_towards_market_intergration.

[99] See Reuters (2014), European power exchanges plan cross-border intraday trading, 10 February 2014, retrieved from http://www.reuters.com/article/2014/02/10/electricity-europe-intraday-idUSL5N0LF24720140210.

Across EU Member States, policymakers and planners expect energy efficiency to be a key energy "supply" resource over the next three decades, meeting a significant share of current electricity and natural gas consumption and contributing as much, if not more, than low carbon electricity to GHG goals. However, energy efficiency is generally not well integrated into investment planning for electricity infrastructure (generation, T&D) in the EU. For instance, planning processes do not consider the cost-effectiveness of energy efficiency as an alternative to new infrastructure investments. As a result, there is a risk that EU Member States could invest too little in energy efficiency in the coming decade and overbuild electricity infrastructure relative to longer-term electricity demand, instead of shifting energy efficiency expenditures over time to be consistent with trends in supply and demand over the next decade.

Renewable generation will also be an important energy source for EU Member States. However, geographical differences in the availability of renewable resources — some of the best wind resources are in northern Europe, whereas much of the hydropower potential is concentrated in central and northern Europe and the best solar resources are in southern Europe — underscore the need for better coordination across Member States. Addressing the uneven distribution and variability of wind and solar resources will also require a coordinated approach to resource and transmission planning. The rapid deployment of renewable energy is responsible for the bulk of current transmission bottlenecks across the EU.[100]

In principle, the NREAP documents provide a foundation for a coordinated approach to renewable energy planning, by requiring EU Member States to specify medium-term plans for resource development, including sectoral targets, policy measures and anticipated impacts, expected imports and exports of renewable generation, and measures to guarantee grid support for renewables. In addition, the EU's Third Energy Package requires the European Network of Transmission System Operators for Electricity (ENTSO-E), an association of TSOs, to draw and publish a non-binding Ten-Year Network Development Plan (TYNDP) for the entire EU every two years. The TYNDP enables a transparent, coordinated approach to developing national and cross-border transmission to support renewable energy. Although the NREAPs and TYNDP provide the basis for greater collaboration among Member States, a coordinated approach to renewable energy development and transmission planning remains a longer-term goal.

EU-wide planning processes complement national transmission investment planning, which TSOs are required to carry out under EU directives. In Germany, for instance, the four TSOs are required by German law to develop scenario-based transmission plans each year, which are submitted to the network regulator (Bundesnetzagentur) for approval. As part of this process, the plans are released to the public and are subject to public consultation.

[100] European Network of Transmission System Operators for Electricity, *Ten-Year Network Development Plan*, 5 July 2012.

3.4 Energy Efficiency Resources: Acquisition, Pricing, and Funding

Several individual Member States of the EU have been active in implementing energy efficiency policies and programs since the 1980s, acting under their own initiatives. During the 1990s, the EU commenced imposing various requirements relating to energy efficiency on all the Member States, including specifying energy efficiency targets.

In 1998, the Council of the European Union approved a resolution on energy efficiency that endorsed a target for the EU as a whole to improve energy intensity of final consumption by an additional one percentage point per year up to 2010.[101] In April 2006, the Energy End-Use Efficiency and Energy Services Directive[102] required EU Member States to adopt, and aim to achieve, an overall national indicative energy savings target of 9 percent by 2016, to be reached by deploying energy services and other energy efficiency improvement measures. The Directive also required Member States to submit National Energy Efficiency Action Plans that listed measures undertaken in the context of the Directive, and to review their effect as far as possible.

The *Europe 2020 Strategy for Smart, Sustainable and Inclusive Growth*[103] was launched by the EC in March 2010 and approved by the heads of states and governments of EU Member States in June 2010. Member States committed themselves to achieving a non-binding 20 percent energy efficiency target by 2020.[104]

In March 2011, the European Commission released an *Energy Efficiency Plan 2011*[105] aimed at saving more energy through concrete measures. The purpose of the plan was to set out ideas for binding measures to save energy to achieve the 20-percent energy efficiency target. Projections at that time showed that the measures implemented since 2007 would achieve only a nine percent reduction in projected “business as usual” energy consumption in 2020 and the 20 percent target would not be met unless further efforts were made.

In October 2012, the EU adopted an Energy Efficiency Directive,[106] which makes some of the measures in the 2011 Energy Efficiency Plan binding on EU Member States. This Directive is the current, major EU legislation that imposes legally binding energy efficiency obligations on Member States designed to help achieve the 20 percent energy efficiency objective and to pave the way for further energy efficiency improvements beyond that date. The purpose of the Directive is to help Member States meet the EU’s 2020 GHG emissions reduction commitments and contribute to meeting EU goals for moving to a competitive low-carbon economy in 2050, in particular by reducing GHG emissions from the energy sector, and by achieving zero-emission electricity production by 2050.

The Energy Efficiency Directive establishes a common framework of measures for the promotion of energy efficiency within the EU. It lays down rules designed to remove barriers in the energy market and overcome market failures that impede efficiency in the supply and use of energy, and provides for the

[101] Council of the European Union, 1998.
[102] European Parliament and Council, 2006.
[103] European Commission, 2010.
[104] This target translates into a savings of 368 million tons of oil equivalent (Mtoe) of primary energy (gross inland consumption minus non-energy uses) by 2020 compared to projected business-as-usual consumption in that year of 1842 Mtoe.
[105] European Commission, 2010.
[106] European Parliament and Council, 2012.

establishment of national energy efficiency targets. The Directive restates the target for the EU as a whole to reduce absolute energy consumption by 20 percent by 2020, relative to business as usual.[107]

The Directive also requires each EU Member State to set an indicative non-binding national energy efficiency target for 2020, based on either primary or final energy consumption, primary or final energy savings, or energy intensity, and report those targets to the EC. In addition, the Directive continues the requirement in the 2006 Energy Efficiency and Energy Services Directive that each Member State must submit a National Energy Efficiency Action Plan and specifies that such plans must be submitted every three years.

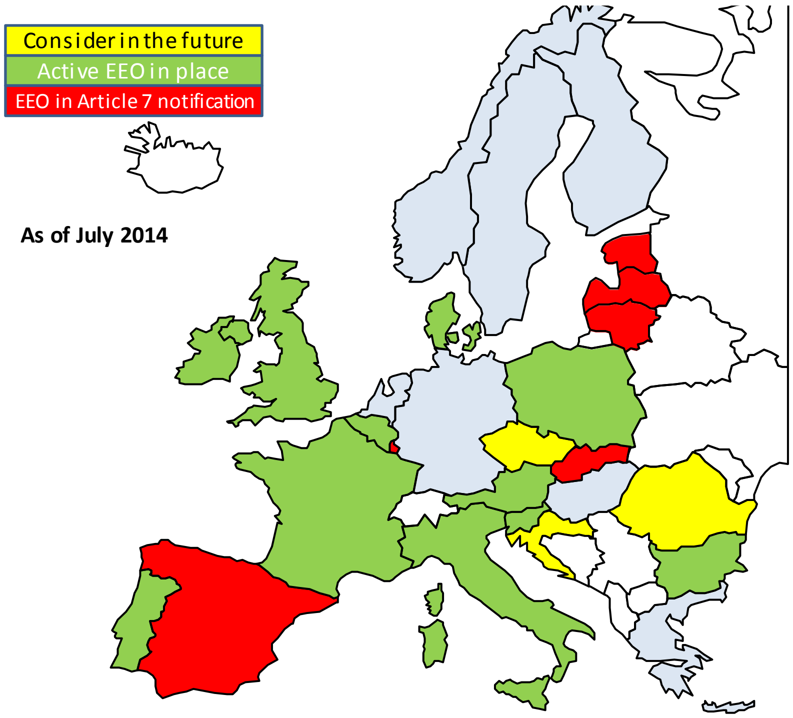
The Directive has important implications for acquisition of energy efficiency as a resource in the power sector, building on the experience of the 10 Member States that have active energy efficiency obligation (EEO) schemes in place. The Directive establishes for the first time an EU-wide policy that promotes obligations on electricity utilities to achieve significant annual end-use energy savings. The Directive stops short of requiring obligations on utilities, however, leaving national governments the option to implement “alternative policies” to achieve energy savings. More specifically, the Directive includes a legal requirement for all EU Member States to do one of the following:

- 1) Establish EEO schemes under which energy distributors or retail energy sales companies are obliged to save every year 1.5 percent of their energy sales, by volume, through implementing energy efficiency measures in end-use customers’ premises; or
- 2) Implement “alternative policies” to ensure that 1.5 percent of new energy savings is achieved every year.

Figure 12 shows the status of EU Member States’ commitments regarding the 1.5 percent energy savings target. In addition to the 10 Member States that already have active EEO schemes in place, seven additional Member States now plan to implement EEO schemes and three have said that they will consider implementing EEO schemes in the future. (The remaining eight Member States have either yet to make a decision or are likely to opt for the “alternative policies” to achieve the 1.5 percent goal.)

[107] Article 3 requires the EU as a whole to reduce absolute energy consumption by 20 percent, stating specifically “that the Union’s 2020 energy consumption has to be no more than 1 474 Mtoe of primary energy or no more than 1 078 Mtoe of final energy.” It is not clear how this relates at an individual Member State level.

Figure 12: Status of EU Member State Commitments Regarding the 1.5 Percent Energy Savings Target



Note: Red indicates Member State is committed to implementing an EEO scheme; gray indicates Member State is adopting "alternative policies."
Source: Eoin Lees of RAP, based partly on information from: http://ec.europa.eu/energy/efficiency/eed/article7_en.htm.

In July 2014, the EC released an energy efficiency policy update which estimates that the EU will only achieve energy savings of 18 to 19 percent in 2020. However, the document also states that if all Member States work seriously to "properly" implement the already agreed legislation, the 20 percent target from the Energy Efficiency Directive can be reached without the need for additional measures.[108] In October 2014, the European Council endorsed an indicative 27 percent energy savings target for 2030, to be reviewed in 2020 with an increase to a 30 percent target "in mind".[109]

3.4.1 Case Study: United Kingdom Energy Supplier Energy Efficiency Obligations

The UK has been imposing energy efficiency obligations on energy suppliers for 20 years and serves as a useful case study of possible roles for regulators and governments in promoting energy efficiency.[110] In the UK, the electricity regulator initiated an EEO requiring energy suppliers to promote energy efficiency in the residential and small business sectors. The government later took over the role of setting the rules for this obligation which then became the major government policy for achieving GHG emissions reductions in the UK residential sector.

[108] European Commission, 2014.

[109] See 2030 Framework For Climate Change, retrieved from http://ec.europa.eu/clima/policies/2030/index_en.htm.

[110] The programs described in this section generally were implemented by obligated parties in Great Britain (i.e., England, Scotland, and Wales). Northern Ireland, which is also part of the United Kingdom, had similar, but separate, programs.

The first EEO implemented in the United Kingdom, and in Europe, commenced in 1994 when the then electricity regulator for England and Wales began an initiative known as the Energy Efficiency Standards of Performance (EESoP). Under this initiative, the regulator required electricity suppliers (i.e., electricity distributor/retailers) with more than 15,000 customers to spend one GBP per residential customer on household and small business energy savings measures. The regulator also set energy savings targets to be achieved by the suppliers.[111] In 2000, the EESoP program was extended by the regulator to all electricity and gas suppliers in the UK with at least 50,000 customers but restricted to residential customers only. The EESoP ran from 1994 until 2002 and became the dominant vehicle through which energy efficiency measures were delivered to residential households in the UK. EESoP had both social goals and environmental benefits. The majority of customers assisted under EESoP 1 (1994 to 1998) were disadvantaged.[112] In EESoP 2 (1998 to 2000) and EESoP 3 (2000 to 2002) suppliers were required to focus around two-thirds of their expenditure on disadvantaged customers.

Commencing in 2002, a new obligation called the Energy Efficiency Commitment (EEC) was established under the *Utilities Act 2000*. Under this obligation, the UK government took over the role of the regulator in setting energy savings targets for energy suppliers. The EEC was the UK government's key energy efficiency policy for existing households and it was expected to reduce domestic CO_2 emissions by one percent per annum. The EEC was implemented in two phases, EEC1 (2002 to 2005) and EEC2 (2005 to 2008). EEC1 required electricity and gas suppliers to achieve an energy savings target of 62 TWh in domestic households in Great Britain.[113] In EEC2 the target almost doubled to 130 TWh. At least 50 percent of this target had to be met in relation to a Priority Group of consumers, defined as those in receipt of certain income-related benefits and tax credits.

In early 2008, the UK government announced that the EEC would be renamed the Carbon Emissions Reduction Target (CERT). The CERT became the government's main policy instrument for reducing carbon emissions from existing households. The CERT ran from 1 April 2008 to 31 March 2011, and required certain gas and electricity suppliers to meet a carbon emissions reduction obligation (carbon obligation). The overall target was 293 million tons of CO_2, measured over the lifetime of measures. At least 40 percent of this target had to be achieved by targeting certain low-income domestic consumers or those over 70 years old — the Priority Group; 73.4 million tons of CO_2 had to be achieved via professionally installed insulation measures; and the obligated energy suppliers had to promote 16.2 million tons worth of carbon savings to those on certain qualifying benefits, such as low-income households receiving child tax credit. The funding for the installation or distribution of measures came from the obligated suppliers. However, they were not required to spend a fixed amount of money per household.

A second energy efficiency obligation, called the Community Energy Savings Programme (CESP), operated in the UK from 1 October 2009 to 31 December 2012.[114] The Department of Energy and Climate Change set an overall carbon emissions reduction target of 19.25 million tons of CO_2. This was to be met through requiring gas and electricity suppliers and electricity generators to deliver energy saving measures to residential consumers in specific low-income areas of Britain. The obligation was placed on all licensed gas and electricity suppliers that had at least 50,000 domestic customers and all licensed

[111] OFFER, 1998.
[112] Ofgem and the Energy Saving Trust, 2003.
[113] Ofgem, 2005.
[114] Ofgem, 2014b.

electricity generators that had generated on average 10 TWh per year or more in a specified three-year period. The CESP was designed to focus the activities of obligated parties into partnerships with local authorities and other local bodies to provide whole-house energy efficiency retrofits in low-income communities. It got off to a very slow start and its overall energy saving target was not met.[115] This was the first time that any EEO target in the UK was not met.

The Energy Companies Obligation (ECO)[116] commenced at the beginning of 2013 to replace the CERT and the CESP. The ECO was introduced to reduce the UK's energy consumption and support people living in fuel poverty.[117] It does this by funding energy efficiency improvements worth around GBP 1.3 billion every year. The ECO places legal obligations for the period 1 January 2013 to 31 March 2015 on the larger energy suppliers to deliver energy efficiency measures to residential energy users. Energy suppliers are obligated under the ECO if they have more than 250,000 domestic electricity or gas customers and supplied more than 400 GWh of electricity or more than 2000 GWh of gas in a year.[118] The ECO operates alongside the Green Deal, which is designed to help people make energy efficiency improvements to buildings by allowing them to pay the costs through their energy bills rather than upfront. The ECO is intended to provide additional support to the Green Deal in the residential sector, with a particular focus on vulnerable consumer groups and hard-to-treat homes.

Under the ECO, energy suppliers are obligated to help improve the energy efficiency of their residential customers' buildings in three distinct areas:[119]

- **Carbon Emissions Reduction Obligation.** Under this obligation, energy companies must concentrate efforts on hard-to-treat homes and measures that cannot be fully funded through the Green Deal. Solid wall insulation and hard-to-treat cavity wall insulation are the primary areas for focus under this target.
- **Carbon Saving Community Obligation.** Under this obligation, energy companies must focus on the provision of insulation measures and connections to domestic district heating systems in low-income communities. This target has a sub-target, which states that at least 15 percent of each supplier's Carbon Saving Community Obligation must be achieved by promoting measures to low-income and vulnerable households living in rural areas.
- **Home Heating Cost Reduction Obligation.** Under this obligation, energy suppliers are required to provide measures which improve the ability of low-income and vulnerable households (the "Affordable Warmth Group") to heat their homes. This includes actions that result in heating savings, such as the replacement or repair of boilers.

For the period 1 January 2013 to 31 March 2015, the overall targets for the ECO are:[120]

- carbon emissions reduction target: 20.9 megatonnes of carbon dioxide;
- carbon saving community target: 6.8 megatonnes of carbon dioxide;

[115] See Ofgem (2013), *Final report of the Community Energy Saving Programme (CESP) 2009-2012*, retrieved from https://www.ofgem.gov.uk/ofgem-publications/58763/cesp-final-report-2013final-300413.pdf.
[116] Ofgem, 2014a.
[117] UK Government, 2014b.
[118] Ofgem, 2013.
[119] Ofgem, 2014a.
[120] UK Parliament, 2012.

- home heating cost reduction target: £4.2 billion of cost savings.

Under the ECO, obligated suppliers are only responsible for implementing energy efficiency programs that provide additional support to the Green Deal in the residential sector, with a particular focus on vulnerable consumer groups and hard-to-treat homes. Consequently, only a small number of energy efficiency measures may be implemented in ECO energy efficiency programs compared with a much broader range of measures in the earlier energy efficiency obligations. In an innovation designed to achieve open and competitive delivery of the ECO, obligated suppliers can purchase carbon dioxide reductions from third party ECO providers. The ECO Brokerage is a market-based mechanism that operates fortnightly, anonymous auctions where ECO providers can sell lots of ECO Carbon Saving Obligations, ECO Carbon Saving Communities, and ECO Affordable Warmth.[121]

ECO is a more complicated scheme than previous EEOs as it has four targets,[122] different metrics for the targets, and administratively was divided into three phases for the 27-month period. Under the Carbon Saving part, it also restricted the traditional loft and cavity wall insulation measures that had underpinned all previous EEOs. Compounded with the very slow start of the Green Deal programme which this part of ECO was expected to work closely with, this has resulted in an almost halving of the insulation industry and the collapse of the Brokerage system in terms of contracts awarded each fortnight.

In response to these problems, the government has extended the life of ECO till 31 March 2017 and effectively lowered the CO_2-saving target within ECO.[123] It also introduced over-generous subsidies available to householders through a Green Deal Home Improvement Fund financed by government. In particular, it offered subsidies of up to £6,000 to pay for solid wall insulation. This resulted in early reduction of the subsidy level followed a few days later by complete closure of the Fund.[124] The future for Green Deal and ECO remains uncertain.

In general, the costs of implementing energy efficiency programs under the various UK energy efficiency obligations are shared among the obligated parties and other entities involved in the implementation of energy efficiency projects. For electricity and gas suppliers, the costs are considered a "cost of doing business" and so are reflected in the prices charged to end-use customers. For electricity generators, the costs are indirectly passed on to customers through increased wholesale electricity prices.

3.5 Renewable Energy Resources: Acquisition, Pricing, and Funding

EU Member States have experimented with several approaches to renewable energy acquisition. For instance, several Member States have used auctions to procure new resources, where a solicitation is

[121] UK Government, 2014a.

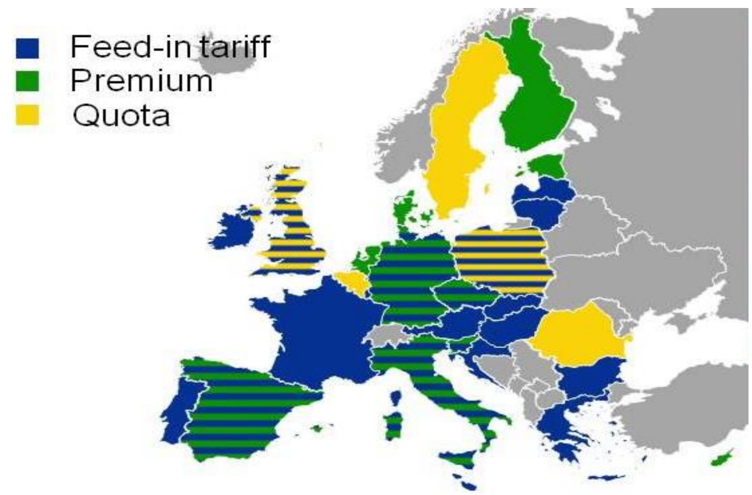
[122] The communities target has a requirement that 15 percent of the CO_2 savings must come from rural properties.

[123] UK Department of Energy and Climate Change (2014). *The Future of the Energy Company Obligation* [Government response]. Retrieved from https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/342178/The_Future_of_the_Energy_Company_Obligation_Government_Response.pdf.

[124] See UK Department of Energy and Climate Change (2014), *Answering Your Questions About the Closure of the Green Deal Home Improvement Fund*, retrieved from https://www.gov.uk/government/publications/answering-your-questions-about-the-closure-of-the-green-deal-home-improvement-fund, and Winch, J. (2014), Was Green Deal cashback scheme rigged? *The Telegraph*, August 2, 2014, retrieved from http://www.telegraph.co.uk/finance/personalfinance/energy-bills/11006180/Was-Green-Deal-cashback-scheme-rigged.html.

issued for a single project (e.g., offshore wind in Denmark) or up to a stated capacity (e.g., onshore wind in France). The auctions may call for a specified per kWh price or for a premium to be paid above electricity market prices.[125] Some EU Member States have also implemented annual renewable energy quotas, similar to US RPS policies, whereby certificates are created by the generation of renewable energy and are bought and sold among electricity providers required to comply with the quota.[126] However, the majority of EU Member States have adopted FITs, either on their own or in combination with other policy mechanisms such as auctions, and the rest of this section will focus on FITs for this reason. Figure 13 depicts the policy support mechanisms for renewable energy in the EU. Note that the Member States that appear striped have a combination of policies.

Figure 13: Renewable Energy Support Mechanisms in the EU[127]



FITs require utilities to purchase electricity from eligible energy technologies for long terms (usually 15 to 20 years) and provide guaranteed grid access, with priority dispatch. FIT prices may be set using a variety of approaches: equal to the expected cost of production plus a profit; equal to the value of production, such as generating at peak (for solar) or including the estimated environmental externality costs or health and national security benefits; or using a sliding or fixed premium over electricity market prices. FIT prices are often differentiated by technology, application, resource intensity, project size, ownership, and other variables.

Twenty of the 28 Member States in Europe use FITs as their primary policy mechanism for promoting renewable generation; another four use FITs as a supportive policy for certain renewable energy technologies.[128]

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125 Klessman, C. (2013, October 24), *Synthesising Opportunities and Challenges for RE Tenders from International Experience and from a Theoretical Perspective.* Presentation before the International Feed-In Cooperation meeting, Brussels, Belgium.
126 Brown, P. (2013, August 7). *European Union Wind and Solar Electricity Policies: Overview and Considerations*. Congressional Research Service.
127 Schmidt, I. (2013, October 24). *The RES Progress Report and the COM Guidance For the Design of Renewables Support Schemes.* Presentation before the International Feed-In Cooperation Workshop, Brussels, Belgium. Retrieved from http://www.feed-in-cooperation.org/wDefault_7/content/10th-workshop/presentations.php.
128 Ragwitz, M., Winkler, J., Klessmann, C., Gephart, M., and Resch, G. (2012, January). *Recent Development of Feed-in Systems in the EU: A Research Paper for the International Feed-In Cooperation*. Retrieved from http://www.feed-in-cooperation.org/wDefault_7/content/research/index.php.

No two FITs are the same, as no two countries share the same policy design or objectives. Some of these policy design differences are discussed below:

- *Eligibility for FIT payments*. FITs in Europe generally allow participation by any entity. Utilities in Germany were initially excluded from qualifying when Germany's FIT was enacted in 1990, but that restriction was removed in 2000. Eligible entities include, but are not restricted to, homeowners; business owners; federal, state, and local government agencies; private investors; utilities and nonprofit organizations.

- *Eligible resources and technologies*. FITs may be designed to access renewable resources that are available and accessible. Germany includes a FIT for geothermal but not for tidal energy or concentrating solar power (CSP), whereas it is the reverse in Spain: no FIT for geothermal, but tidal and CSP are eligible.

- *Length of contract*. Contract lengths vary between five and 25 years, with most of them being between 15 and 20 years.[129]

- *How prices are adjusted over time*. A commonly cited best practice in the design of FITs is to decrease FIT payments for new plants by a specified percentage every year, to take advantage of technology advances, technology cost reductions, and economies of scale. Germany, Greece and Slovenia are among the countries that have such an approach. The exact percentages may differ by technology. The annual percentage reduction may be fixed, such as the annual 1.5 percent reduction in FIT payments for new wind projects in Germany, or decided annually.[130] For more emerging technologies such as offshore wind, the tariff degression may not take effect until later. In Germany, for example, the FIT rate for offshore wind projects is fixed until 2018, then declines 7 percent annually.[131]

- *Location or application* (such as offshore wind or building-integrated PV). France and Greece both have higher FIT rates for projects located on islands that are not connected to the mainland grid.[132] Germany and other countries have separate rates for offshore wind that are higher than that for onshore wind.[133] France has differentiated rates for building-integrated PV as opposed to utility-scale PV projects over 250 kW.

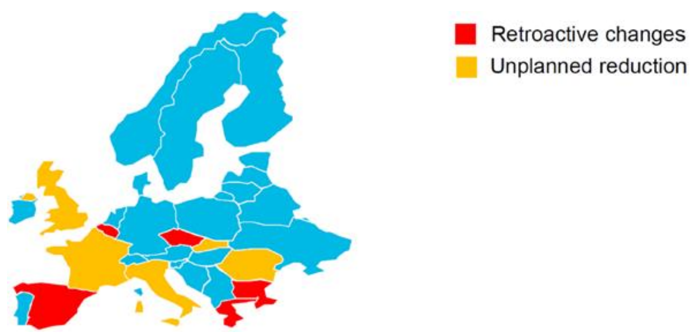
- *Program or project size caps*. Several types of limits, or caps, can be applied, such as technology caps (often varying by technology); caps on the capacity of individual projects; or caps on total program cost (annual, or total over multiple years). Switzerland, for example, has a total funding cap of 320 million Swiss francs (roughly $350 million), with 50 percent allocated to hydro, 30 percent to wind, and 5 percent to PV. The PV share will increase to 10 percent should average PV costs fall below 0.6 Swiss francs per kWh (0.67 U.S. cents/kWh).[134] The United Kingdom's FIT

[129] Couture, T., Cory, K., Kreycik, C., and Williams, E. (2010, July). *A Policymaker's Guide to Feed-In Tariff Policy Design*. National Renewable Energy Laboratory. Retrieved from http://www.nrel.gov/docs/fy10osti/44849.pdf.
[130] Ragwitz et al, 2012.
[131] International Energy Agency and International Renewable Energy Agency. *Joint Policies and Measures Database.* Retrieved from http://www.iea.org/policiesandmeasures/renewableenergy.
[132] Couture et al, 2010.
[133] International Energy Agency and International Renewable Energy Agency. *Joint Policies and Measures Database.*
[134] Ibid.

limits individual project size to 5 MW, with anaerobic digestion, hydro, PV, and wind the eligible technologies. (Larger renewable projects are covered by the UK's quota scheme.) Micro gas-fired CHP units of up to 2 kW also qualify.[135]

- *Resource intensity* (e.g., different rates for wind or solar energy depending on the site's resource availability). Germany's and Switzerland's FIT, as does China's, offers higher FIT rates for lower wind speed sites.[136] Such a policy encourages geographic diversification of wind energy projects, making aggregate wind output less variable.[137]

Figure 14: Retroactive Changes and Reductions in FIT Tariffs in the EU[138]



Note: Blue indicates no change in policy.

While the FIT remains the world's most common mechanism for promoting renewables, recent activity in EU has involved scaling back such policies, as exemplified by legislative shifts in Germany and Spain. For the past few years, Germany has been easing its support for renewables, as falling costs have made solar PV, wind, and biomass increasingly competitive with conventional generation. For example, in 2012, Germany lowered FIT payments, instituted a cumulative cap of 52 GW on FIT-eligible solar PV, and ceased exempting certain renewable energy producers and consumers from FIT surcharges. New amendments set to take effect in August 2014 require new plants of a given size (e.g., 100 kW in 2017) to rely on direct power marketing, supplemented by premium payments, rather than fixed FIT prices. Unlike Germany, Spain has faced an ever-widening gap between electricity costs and revenues caused, in large part, by longstanding caps on electricity prices. After instituting several rounds of retroactive cuts to FIT prices and caps to FIT projects, Spain halted its FIT in 2012. Then, in 2013, it eliminated a measure that certain RE generators had used to sell their power at market prices plus a bonus premium. In February 2014, the country's Energy Ministry issued a draft approach for replacing Spain's FIT with a guaranteed 7.39 percent rate of return for current RE projects. Spain's story, in particular, underscores the need to ensure stable public policies combined with sound financial mechanisms to ensure RE investments can and will be paid for. Figure 14 illustrates which countries have imposed reductions in FIT tariffs or retroactive changes in the EU.

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135 Feed in Tariffs Ltd. *Eligible Energy Sources*. Retrieved from http://www.fitariffs.co.uk/eligible/energies/.
136 Couture et al, 2010.
137 Reducing variability through geographic diversity also applies to solar. The difference in FIT payments in China has not been significant enough to forestall concentration of wind resources in northern China. Massive wind curtailment and governmental action to reduce additional wind capacity in northern China has resulted in some wind capacity being developed outside of northern China.
138 Schmidt, 2013.

3.5.1 Supporting Resources

In a number of EU Member States that do not have capacity payment mechanisms, the rapid scale up of wind and solar generation has had a significant impact on the financial viability of existing thermal generators by depressing energy-market prices and leaving thermal generators unable to earn sufficient revenues to recover their going-forward costs. This, together with the high cost of natural gas in Europe relative to the price of coal, has led a number of companies to retire or "mothball" power plants, particularly flexible and low-emission gas-fired generators, some of which were only recently built. This trend has raised concerns among policymakers and regulators, as more flexible generation is expected to be needed in the future to provide ramping support (fast ramps lasting for multiple hours, fast start-up and stop, and the ability to operate at low minimum output) for higher penetrations of wind and solar energy.

In response, many of these Member States are currently considering a range of potential capacity payment mechanisms, generally falling under two models: (1) customer-based; (2) central buyer.[139] Under the more decentralized customer-based model (e.g., France), retail suppliers are required to hold tradable certificates sufficient to meet their projected customer peak demand in a given period, and capacity payments are determined on the basis of certificate prices. In the more centralized central buyer model (e.g., UK), the system operator sets capacity requirements for the system based on a load forecast, and conducts a centralized auction to procure the required capacity.

The EC issued restrictive guidelines for capacity payment mechanisms, including a requirement that such mechanisms be non-discriminatory — open to existing generation, new generation, generation from outside a given member state with transmission access to the member state's system, and demand-side resources.[140] The EC has also expressed concerns about potential conflicts between national mechanisms for ensuring resource adequacy and the functioning of coupled markets, although mitigation measures are available and the emergence of an EU internal market would likely lead to more regional strategies to resource adequacy.[141] None of the proposed capacity payment mechanisms currently value generator flexibility.[142]

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[139] There are other models currently in use in the EU, including direct payments (e.g., Spain) and a strategic reserve mechanism (e.g., Sweden).

[140] See European Commission (2013). *Generation Adequacy in the Internal electricity market – guidance on public interventions* [Staff Working Document], 5 November 2013. Retrieved from http://ec.europa.eu/energy/gas_electricity/doc/com_2013_public_intervention_swd01_en.pdf.

[141] For a more detailed version of this argument, see Baker, P., and Gottstein, M. (2013), *Capacity Markets and European Market Coupling – Can they Co-Exist?* [Discussion draft], RAP, March 13, 2013.

[142] See Gottstein, M., and Skillings, S.A. (2012). *Beyond Capacity Markets - Delivering Capability Resources to Europe's Decarbonized Power System.* 2012 9th International Conference on the European Energy Market (EEM), IEEE: 1-8.

3.6 Renewable Energy Integration

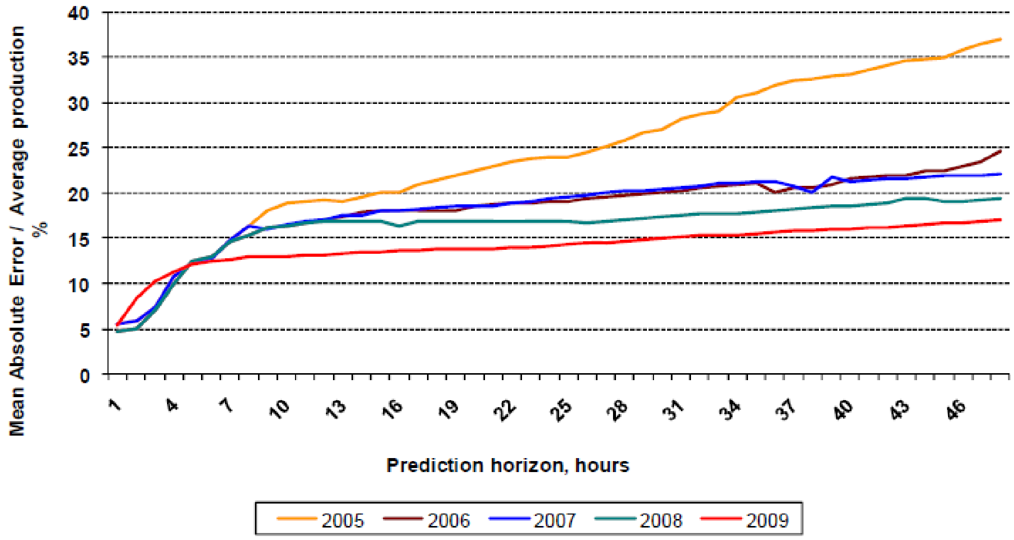
Certain EU Member States have been pioneers in adopting strategies to integrate variable generation (VG). Several of these strategies are described below: (1) forecasting for VG, (2) flexibility of dispatchable generation capacity, (3) establishing and updating grid codes, (4) energy storage, (5) demand response, and (6) recognition of need for new transmission. Faster generator scheduling and dispatch has also been an important factor, and will be discussed in the following section. These strategies have helped significantly reduce wind curtailment. For instance, in Italy wind curtailment fell from 11 percent of total wind generation in 2009 to just over 1 percent in 2012.[143]

1) Variable generation forecasting: All countries and regions with high levels of variable generation have adopted VG forecasting and continuously make enhancements to their forecasts. Spain, for instance, relies on five independent wind forecasts. REE, the Spanish grid operator, uses a central wind forecast for all wind generation. The wind forecast provides hourly wind forecasts for the next ten days, and a forecast by transmission system node that is updated every 15 minutes for the next 48 hours. Confidence intervals at 15 percent, 50 percent, and 85 percent are provided, with the 85 percent level used to determine if there are enough units committed. [144] REE has reported that improvements in wind forecasting, shown in Figure 15, have resulted in fewer reserves needed to account for wind forecast errors, particularly day-ahead.

German TSOs utilize several forecasting services at the same time and use a weighted sum of these forecasts adjusted to observed weather patterns. For example, Amprion uses ten different wind forecasts which are entered into a “combination tool,” which then produces an optimal forecast while taking into account the weather situation. 50Hertz combines three different forecast tools to create a weighted sum forecast for the TSO’s area and for Germany as a whole. The combination of forecast models takes advantage of the fact that these models deal with weather situations differently, with some performing better under specific conditions while other models are better predictors under other specific weather conditions. [145]

[143] Debra Lew, Lori Bird, Michael Milligan et al., “Wind and Solar Curtailment,” NREL Conference Paper, September 2013, http://www.nrel.gov/docs/fy13osti/60245.pdf.
[144] NERC, *IVGTF Task 2.1 Report: Variable Generation Power Forecasting for Operations* (Princeton, NJ: NERC, May 2010), http://www.nerc.com/docs/pc/ivgtf/Task2-1%285.20%29.pdf.
[145] B. Ernst, U. Schreier, F. Berster, J.H. Pease, C. Scholz, H.P. Erbring, S. Schlunke and Y.V. Makarov, *Large-Scale Wind and Solar Integration in Germany* (Richland, WA: Pacific Northwest National Laboratory, February 2010), http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19225.pdf.

Figure 15: Hourly Wind Forecast Error for Next 48 Hours, 2005–2009[146]



<u>2) Extraction of flexibility from existing generation:</u> Rapid increases in VG have led to efforts to extract greater flexibility out of existing dispatchable generation. Existing dispatchable generation can generally provide more flexibility with small increases in capital and operation costs. For instance, Denmark required its thermal-fired CHP units to retrofit and be capable of ramping down to 20 percent of their rated capability. Individual coal plants in the United States are also capable of ramping down to this level, although it varies considerably by unit. *Power Perspectives 2030*, a study of the feasibility of Europe's plan to reduce overall greenhouse gas emissions 80 percent by 2050, found that a more flexible portfolio of non-renewable supply resources is a key component of an economic long-term solution to VG integration. While some of this increased flexibility will come from an increase in the number of back-up generators with very low capacity factors, the study found that there are more cost-effective options, such as more flexible gas-fired combined cycle plants. These plants will constitute the core of a non-renewable supply portfolio and will operate at capacity factors comparable to what they operate at today, though with more erratic day-to-day operating profiles. Together with more responsive demand, expanded transmission systems and larger balancing areas, more flexible generating resources are needed to optimize production and consumption. Essentially what is needed is a portfolio of "flexible base-load" supply resources capable of matching net load – with its shrinking share of round-the-clock demand – without compromising efficiency.[147] The IEA recently published a report on variable resource integration that reached the same conclusions.[148]

<u>3) Establishing and updating grid codes</u>: Grid codes have also been a key component of VG integration in the EU. European countries were among the first to adopt grid codes for wind; indeed, the German grid code has been used as the basis for grid codes for wind in other countries, including China and the

[146] Jorge Hidalgo López, "Wind Development and Integration Issues and Solutions," Presentation before the Northwest Wind Integration Forum, Portland, OR, July 29-30, 2010, http://www.nwcouncil.org/energy/wind/meetings/2010/07/WIF%20TWG%20072910%20Hidalgo%20072610.pdf.

[147] *Power Perspectives 2030*.

[148] *The Power of Transformation – wind, sun and the economics of flexible power systems,* IEA 2014, http://www.iea.org/w/bookshop/add.aspx?id=465

United States. Frequent updating of grid codes has allowed them to evolve in step with industry changes. Germany, for instance, amended its grid code to require thousands of distributed solar installations to be retrofitted to withstand grid disturbances, at considerable expense.

4) Energy storage: Energy storage is also widely recognized to be necessary for integrating higher penetrations of renewable energy within the EU. However, current market design and regulatory frameworks are inadequate to support significant levels of investment in storage facilities, in part because renewable energy is changing the business model for storage. Presently, the vast majority of energy storage in the EU is in the form of pumped hydro energy storage (PHES), which pumps water to a reservoir during the evening when market prices are cheap and discharges it during the day when prices are expensive. Higher penetrations of solar energy have reduced market prices during peak periods, which in turn has reduced the viability of this business model. A larger share of future revenues for storage providers may come from ancillary services and capacity markets, but these markets often lack transparency and regulatory certainty.[149]

The EU regulatory and business communities generally expect that the business model for energy storage will evolve around market price signals and non-discriminatory access to the grid. This requires, however, a number of changes to current market design and regulatory frameworks, such as: clearer rules for storage interconnection; cross-border markets for ancillary services and rules for participation in those markets; market and regulatory mechanisms to ensure an equal playing field among storage, flexible generation, transmission, and demand response; clarification on whether TSOs can own and operate storage; transmission access charges that treat storage as a generator or a load (but not both) and are based on cost causality.[150] Many of these changes will necessitate greater harmonization of EU markets and regulations.

5) Demand response: Demand response is being viewed as increasingly important not only for VG integration but also to increase market liquidity and competition. Demand response currently accounts for only 4 percent of demand in Europe. Barriers to entry to demand response are high in Europe, and only the larger players are participating, with virtually no participation from residential or commercial customers. Different countries have different frameworks and requirements for demand response, ranging from time-of-use to bilateral interruptible contracts, critical peak pricing tariffs and reserve capacity bidding solicitations, all of which serve to constrict the development of a more robust market for demand response. The development of more standardized definitions for demand response across Europe is needed.[151]

Demand response can include shifting electricity demand to different time periods when there is excess supply. Denmark is a prime example. Denmark receives over 30 percent of its annual energy production

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[149] stoRE Project, "European Regulatory and Market Framework for Electricity Storage Infrastructure: Analysis, stakeholder consultation outcomes and recommendations for the improvement of conditions," June 2013, http://www.store-project.eu/documents/results/en_GB/european-regulatory-and-market-framework-for-electricity-storage-infrastructure.
[150] See, for instance, European Commission Directorate-General for Energy, "The future role and challenges of Energy Storage," 2013 DG ENER Working Paper, http://ec.europa.eu/energy/infrastructure/doc/energy-storage/2013/energy_storage.pdf; stoRE Project, "European Regulatory and Market Framework for Electricity Storage Infrastructure."
[151] M. Norton, H. Vanderbroucke, E. Larsen, C. Dyke, S. Banares, C. Latour, and T. Vu Van, *Five Critical Issues to be Addressed to Enable DSR at the EU Level*, European Network of Transmission System Operators, September 2014, https://www.entsoe.eu/Documents/Publications/Position%20papers%20and%20reports/140915_DSR_Policy_web.pdf.

from wind and has a large number of district heating plants that produce electricity and steam.[152] Wind plants, with near-zero production cost, are treated as must-run facilities. The district heating plants operate primarily to supply heat to homes and businesses. Therefore, the supply of electricity in Denmark ramps up and down with no particular correlation to fluctuations in demand. The country is blessed with a neighboring power system that is nearly all hydro and currently has enough interconnection capacity with the neighboring system to manage these cycles. But as the country seeks to expand wind generation to 50 percent of production by 2020, this will no longer suffice, so a program is in development to expand demand response (including increased use of electric heat pumps) and increase the capacity of thermal energy storage associated with the country's district heating systems.[153]

One analysis compared a business as usual case, where new generation is built to meet the incremental needs for reserves, to another scenario where 10 percent of the aggregate demand in the course of a day is assumed to be "moveable" from periods where supply is less available to periods where it is more available. The result is less need for backup capacity, less need for curtailment of least-cost resources like wind and solar, and less need for transmission, all leading to a net reduction in investment needs of more than 20 percent over the next 15 to 20 years.[154]

6) Recognition of need for new transmission: Transmission is also a key issue in Europe as progress continues towards developing a fully liberalized single integrated European electricity market. New transmission and greater collaboration between transmission system operators are seen as essential not only to support the integrated market but to enable Europe to meet its renewable energy and carbon reduction targets. Numerous studies emphasize the need for new transmission to integrate large amounts of centralized renewable energy at Europe's periphery (e.g. large scale solar in the South and offshore wind in the North Seas).[155] TSOs are currently planning to increase their rate of investment by 70 percent by 2020, while the DG Climate Roadmap 2050 suggests that the rate of overall grid investment will need to double by 2025 and triple by 2040. In monetary terms, this is likely to translate into a requirement of between €273 and 420 billion of transmission investment by 2050.[156]

Achieving sufficient investment in new transmission will be challenging. Rates of construction of new transmission lines have been decreasing in Europe since the 1970s and the European Commission believes that current arrangements will only deliver 30 percent of the investment required by 2020 because of financing difficulties, the asymmetry of costs and benefits associated with cross border interconnection, and the inability of existing arrangements to capture the benefits of interconnection

[152] C. Morris, "Denmark Gets More Than 30 Percent of Its Power from Wind,´ *Renewables International*, April 2, 2013, http://www.renewablesinternational.net/denmark-gets-more-than-30-percent-of-its-power-from-wind/150/505/60282/.
[153] L. Schwartz, K. Porter, C. Mudd, S. Fink, J. Rogers, L. Bird, M. Hogan, D. Lamont, and B. Kirby, *Meeting Renewable Energy Targets at Least Cost: The Integration Challenge*, May 2012, http://www.raponline.org/featured-work/meeting-renewable-energy-targets-in-the-west-at-least-cost-the-integration.
[154] McKinsey & Co., KEMA, Imperial College London and European Climate Foundation, *Power Perspectives 2030: On the road to a decarbonized power sector*, October 2011, http://www.roadmap2050.eu/pp2030.
[155] Roadmaps relevant to this discussion include: EG ENERGY (2011) "Energy Roadmap 2050;" DG CLIMA (2011) "Roadmap for Moving to a Competitive, Prosperous, Low Carbon Europe;" ECF (2010) Roadmap 2050: A Practical Guide to a Prosperous, Low Carbon Europe;" ECF (2011) "Power Perspectives 2030: On the Road to a Decarbonized Power Sector;" Eurelectric (2009) "Power Choices;" Greenpeace (2012) "Battle of the Grids; How Europe Can Go 100 percent Renewable and Phase out Dirty Energy;" European Gas Advocacy Forum (2011) "Making the Green Journey Work;" SUSPLAN (2012) "Development of Regional and Pan-European Guidelines for More Efficient Integration of Renewable Energy into Future Infrastructures."
[156] Communication from the Commission to the European Parliament, the Council and the Committee of Regions, COM (2011) 885 final, Energy Roadmap 2050, http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=COM:2011:0885:FIN:EN:PDF.

from a "European" perspective.[157] This presents a significant risk in achieving European decarbonization goals, security of supply and market integration. For example, modeling by the European Climate Foundation suggests that if only half of the projected transmission capacity is developed, curtailment of renewable generation could increase up to tenfold, electricity prices would become more volatile, and an increase in operating reserves would be needed.[158]

In conclusion, although there has been significant success with these strategies, Europe has been less progressive in other aspects of renewable integration. Expansion of balancing across regional markets spanning several Member States would offer significant additional integration benefits, but there has not been much progress in this regard. In addition, the plan to couple intra-day and balancing markets is years behind schedule.

3.7 Generator Dispatch

Wholesale generation and ancillary services markets in the EU are designed to minimize the costs of operating power systems. Environmental considerations are incorporated into dispatch through generator variable costs (e.g., as CO_2 prices in the EU-ETS) or through environmental standards (e.g., as in operating hours limits under the LCP and IED). The EU currently has a priority dispatch policy for renewable generation.

There are many wholesale market models across the EU, with different approaches to generator scheduling and ancillary services procurement. However, they are all designed on the basis of a merit order, where generators are dispatched in order of increasing short-run marginal cost, subject to system security, transmission, and regulatory constraints. With the exception of Nord Pool, most markets within the EU have historically been dispatched nationally, with bilateral trading among countries, rather than through a centralized dispatch that extends across multiple countries.[159] Market coupling, described above, allows scope for a harmonization of dispatch without the need for a single system operator and common market rules across countries. Once full market coupling is completed, price convergence among markets should reflect a convergence in dispatch.

Environmental attributes are not explicitly considered in determining dispatch order, but are integrated into dispatch through generator costs or regulations. For carbon, this is primarily through the EU-ETS, which requires generators to buy allowances to cover their CO_2 emissions, and the LCP and IED, which require large thermal generators to meet emissions standards through installing pollution control equipment. In both cases, the variable cost of operating high polluting generators increases, which improves the competitiveness of less polluting generators in the dispatch order. The LCP and IED also impose mandatory constraints on generator dispatch, by limiting the operating hours of certain generators if they are not able to meet emissions standards.

Article 16 of the Renewable Energy Directive (Directive 2009/28/EC) requires that EU Member States

[157] Zachmann, G. (2010). *Power to the People of Europe*. Bruegel.

[158] European Climate Foundation (2011). *Power Perspectives 2030.* Retrieved from http://www.roadmap2050.eu/attachments/files/PowerPerspectives2030_FullReport.pdf.

[159] Even before regional market coupling in northwest Europe in 2014, there was a significant amount of interregional trading among Member States, enough that for most hours, short-term market prices equalized among several of them. For instance, the Dutch electricity market is well integrated with its neighbors both to the north — the British Isles and Scandinavia — and to its east and south — Belgium, France, and Germany. In 2011, price convergence occurred 70 percent of the time between the Netherlands and Belgium, almost 90 percent of the time with Germany, and about 7 percent of the time with Norway.

grant priority to renewable generation in dispatch, based on transparent and non-discriminatory criteria, and to the extent that it does not compromise system security. Many renewable generation technologies (e.g., wind, solar) have very low variable costs. With economic dispatch, this means that, in principle, under normal conditions they are first to be “dispatched.” However, system operators may curtail renewable generation when the transmission system is congested, when thermal and hydropower generators are operating near minimum operating levels, or when high penetrations of non-synchronous renewable generation threaten system frequency. The Renewable Energy Directive only requires system operators to take measures to minimize inappropriate curtailment of renewable energy, and it does not define “inappropriate.”

A number of EU Member States have shifted to faster generator scheduling and dispatch and reserve sharing, as a strategy for VG integration. For example, Germany operates as a single price area energy market, which includes day-ahead, intra-day, and reserves markets. The intra-day market allows bids to be placed up to 45 minutes before scheduled delivery.[160] All renewable energy is pooled amongst the TSOs, and energy and costs are equalized based on the real-time redistribution of the renewable energy and associated imbalances in proportion to the load shares in each balancing area. The TSOs are responsible for balancing the difference between their 15-minute shares of forecasted renewable energy and their share of actual renewable energy production.[161] During the day, the TSOs change their market positions by buying and selling in the intraday market based on updated short-term variable generation forecasts.[162] Table 2 depicts the reduction in reserves from sharing reserves among multiple TSOs.

Table 2: German Reserve Reductions through Shared Secondary Reserve System (MW)[163]

TYPE OF RESERVE	UP RESERVES BEFORE	UP RESERVES AFTER	DOWN RESERVES BEFORE	DOWN RESERVES AFTER
Primary Regulation	135	135	N/A	N/A
Secondary Reserve	630	532	-450	-464
Tertiary Reserve	350	288	-756	-532

[160] Ernst, B., Schreier, U., Berster, F., Pease, J.H., Scholz, C., Erbring, H.P., Schlunke, S., and Makarov, Y.V. (2010, February). *Large-Scale Wind and Solar Integration in Germany*. Richland, WA: Pacific Northwest National Laboratory, p. 25. Retrieved from http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19225.pdf.
[161] Ernst, B., Oakleaf, B., Ahlstrom, M.L., Lange, M., Moehrlen, C., Lange, B., Focken, U., and Rohrig, K. (2007). Predicting the Wind. *IEEE Power and Energy Magazine* 5, No. 6, November/ December 2007, pp. 78-89. Retrieved from http://ieeexplore.ieee.org/xpl/login.jsp?tp=&arnumber=4383126&url=http%3A%2F%2Fieeexplore.ieee.org%2Fxpls%2Fabs_all.jsp%3Farnumber%3D4383126.
[162] B. Ernst, U. Schreier, F. Berster, J.H. Pease, C. Scholz, H.P. Erbring, S. Schlunke and Y.V. Makarov, *Large-Scale Wind and Solar Integration in Germany*, prepared for the DOE (Richland, WA: Pacific Northwest National Laboratory, February 2010), http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19225.pdf.
[163] Ibid.

3.8 Carbon Pricing

The EU Emissions Trading Scheme (ETS) has been in operation since 2005 and is the largest ETS in the world in terms of annual emissions from covered emitters. The EU ETS currently covers CO_2 emissions from about 11,500 large emitters representing about half of all EU CO_2 emissions (or 45 percent of all GHG emissions).[164] Electricity generators represent the largest share of covered emissions. In order to reduce the complexity of the scheme, small emitters — defined as facilities emitting less than 25,000 tonnes of CO_2 annually — are generally not covered. For phase 3 (2013-20), the cap is slated to decrease by 1.74 percent per year, bringing the 2020 cap to 21 percent below the level of the initial 2005 cap.

In the first two phases of the ETS (2005–2007) and (2008–2012), allowances were allocated largely free of charge, although some sectors were subject to benchmarked allocation (so that relatively efficient emitters in each industry received larger allocations). Since the beginning of phase three in 2013, auctioning is the "default" approach to allowance allocation. This move toward auctioning was partly in reaction to the ability of generators to pass on the "cost" of the freely allocated allowances to end-users, creating windfall profits for generators. Some Member States, including Poland (which has a relatively coal-intensive power sector), are phasing out free allocations to the power sector more slowly, with plans to gradually eliminate free allocations to the power sector by 2020. These slower Member States agreed to implement plans to spend amounts equal to at least three times the amount of the free allowances on programs to reduce emissions in their national power industries.[165]

The ETS Directive stipulates that at least half of the revenues from the auctioning of general allowances should be used to combat climate change within the EU, with some funds to be used in developing countries. A recent independent analysis concludes that if the EU were to auction all allowances and "recycle" auction revenue into additional funding for end-use energy efficiency programs — for example by expanding the utility programs described above — this would substantially reduce end-use electricity bills while bolstering power sector emissions reductions.[166] To put these results in another way, there is significant scope to lower the cap without significantly raising energy bills for end-users, if there is a concurrent expansion of energy efficiency programs.[167]

3.9 Current Issues and Concluding Comments

The EU is facing multiple interrelated challenges in the electricity sector, which have engendered three critical, but as yet unresolved, issues. Although many EU Member States have already made important strides toward GHG emission reduction, the non-binding 2050 objectives that EU leaders have announced imply the need for continuing transformation of the power sector, with sustained increases in end-use energy efficiency and development of a system that supports much higher penetration of renewables. Second, the EU is still working toward the goal of an integrated, EU-wide electricity sector with harmonized rules, institutions and regulations. The EU is faced with the task of ensuring that this integrated electricity market will support objectives for long-term GHG emission reductions. Third, many

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[164] See European Commission Climate Action, *EU ETS*. Retrieved from http://ec.europa.eu/clima/policies/ets/index_en.htm.

[165] See European Commission Climate Action, *Auctioning*. Retrieved from http://ec.europa.eu/clima/policies/ets/cap/auctioning/index_en.htm.

[166] Sijm et. al. (2013). *Investing EU ETS Auction Revenues into Energy Savings*. Retrieved from http://www.ecn.nl/docs/library/report/2013/e13033.pdf.

[167] For discussion of the emissions reductions achieved under the ETS, see Ellerman (2010), *Cap or trap? How the EU-ETS risks locking in carbon emissions*, Sandbag, retrieved from www.sandbag.org.uk/site_media/pdfs/reports/caportrap.pdf, and IETA (2014, March), *European Union: The World's Carbon Markets: A Case Study Guide To Emissions Trading*.

national governments are undertaking efforts to revamp their national policies — such as the UK's Electricity Market Reform and Germany's *Energiewende*. These national discussions are being driven both by local priorities and EU policies (e.g., the Large Combustion Plant Directive). At the same time, national reforms will also affect ongoing EU policy discussions. Given that EU objectives — renewable integration in particular — will require careful coordination across the EU, designing national policies in a complementary fashion is very important.

At the level of policy mechanisms, EU energy efficiency, renewables, and emissions trading policies are subject to ongoing debate. In energy efficiency, the main policy debate will continue to be the level of the 2030 target and whether it will be binding. The EU's own assessment indicates net benefits from a 40 percent 2030 target, although the EU is currently proposing only a 30 percent target.[168] For the power sector, there will be continued debate over whether Member States will choose to implement the 1.5 percent annual energy efficiency obligations on utilities, or whether they will instead choose 'alternate policies' to achieve the same savings.

For renewable energy, policymakers have closely scrutinized both the level of FITs and the way in which FIT costs are allocated. Several countries have implemented sharp, unplanned cuts to FIT rates, sometimes retroactively; imposed taxes on renewable energy systems, also sometimes retroactively; and imposed moratoriums on either the issuance of new FIT contracts or on the development of new FIT-eligible projects — all of which may undermine the growth of the renewable energy industry over the longer term. Other countries are proceeding more cautiously with changes to renewable energy support systems. There will be a continuing debate about how to give adequate incentives for renewable energy development in a way that maintains affordability and supports economic growth.

Certain EU Member States, including Denmark, Germany, Ireland, Portugal, and Spain, are world leaders in integrating large amounts of variable generation and have pioneered several integration strategies, such as forecasting, grid codes and interconnection modeling requirements. However, integration challenges remain. Integrating large amounts of intermittent wind and solar energy on the grid will require new transmission investment for greater interconnection among EU Member States, but also an adequate portfolio of flexible supporting resources, including demand response, gas-fired generation, and energy storage, within each Member State. Attracting investment in a sufficiently flexible portfolio of capacity resources requires a critical examination of the current state of electricity market design and implementation. Some EU Member States have established (or are considering) capacity payment mechanisms to address shortfalls in energy market revenues. Others (e.g., Germany) appear to be moving in a different direction, looking at identifying and remedying flaws in the current implementation of energy and ancillary services markets. In some cases (e.g., the UK) both tracks are being pursued simultaneously. Where capacity remuneration mechanisms are under consideration, the EC and Member States are still in ongoing discussions on ways to ensure that capacity markets to support national grid reliability can be reconciled with the EU integrated electricity market.

The ETS is also a subject of ongoing debate. Most observers agree that there is scope to lower ("tighten") the cap, in light of weak economic growth, improvements in energy efficiency, and strong growth of renewable energy. However, there is much debate regarding the degree of tightening and what the effects the tightening will have on allowance prices. An important part of the ETS discussion — which is sometimes a source of confusion — is how the ETS interacts with other aspects of energy

[168] See WWF (2014). *Commission dresses up business as usual 30% energy efficiency target as success*. Retrieved from http://mediterranean.panda.org/?226130/Commission-dresses-up-business-as-usual-30-energy-efficiency-target-as-success.

policy, particularly energy efficiency programs. As noted above, there is significant scope to lower the cap *without* significantly raising energy bills for end users, if the tightening is coupled with an expansion of energy efficiency programs (which reduce both the total cost of electricity and demand for GHG allowances) — although many observers and decision-makers seem to believe that higher prices are a desirable outcome of a tighter cap.

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4. Brazil

4.1 Institutions and Functions

Significant structural and policy reforms over the last decade have had important and positive results for Brazil's power sector. Of particular note is that the country has achieved almost universal access: 99 percent of the population is connected to the grid.[169] Second, Brazil has been able to make power sector investments to meet quickly growing demand, with significant contributions from non-hydro renewable resources and, increasingly, end-use energy efficiency. Brazil has substantial hydro resources — it produces more than two-thirds of its electricity from hydroelectric facilities — but it has also invested strongly in other renewables and has done well with integrating them into the system, so that today they produce about 20 percent of total electrical output.[170]

Brazilian energy policy is set by means of laws (legislation) and decrees (executive or regulatory authority). The principal institutions responsible for developing and implementing national energy policy are the Energy Policy National Council (CNPE), the Ministry of Mines and Energy, and the National Electric Power Agency (ANEEL).

CNPE is an advisory board to the President made up of ministers and heads of regulatory agencies, among others. CNPE's functions include proposing national energy policy, proposing generation supply reliability criterion, and approving the auction of certain "strategic" power projects.
The Ministry of Mines and Energy (which also coordinates with CNPE) has the executive responsibilities for following CNPE directives. The ministry is responsible for planning, monitoring, and appointing the top executives in the Market Operator and System Operator. It also has special powers to intervene in the markets, to be exercised in cases of short-term supply shortages.

The National Electric Power Agency, ANEEL, is an independent regulatory entity, overseeing power production, transmission, and distribution of energy, as well as the trading of electricity. Its members are appointed to fixed terms of office that do not coincide with that of the President. Established in 1996, it performs the functions that are normally associated with economic regulation, including price setting, fixing the conditions for accessing the networks, supervising auctions, granting concessions, approving market rules and grid codes, and supervising the Market Operator and System Operator.[171]

Two smaller advisory institutions are the Energy Research Company (EPE), which is under the jurisdiction of the Ministry of Mines and Energy and is in charge of giving technical support to the ministry in planning studies in the wider sense (generation, transmission, auctions, etc.) and the Electricity Sector Monitoring Committee (CMSE), which monitors short-term supply reliability.

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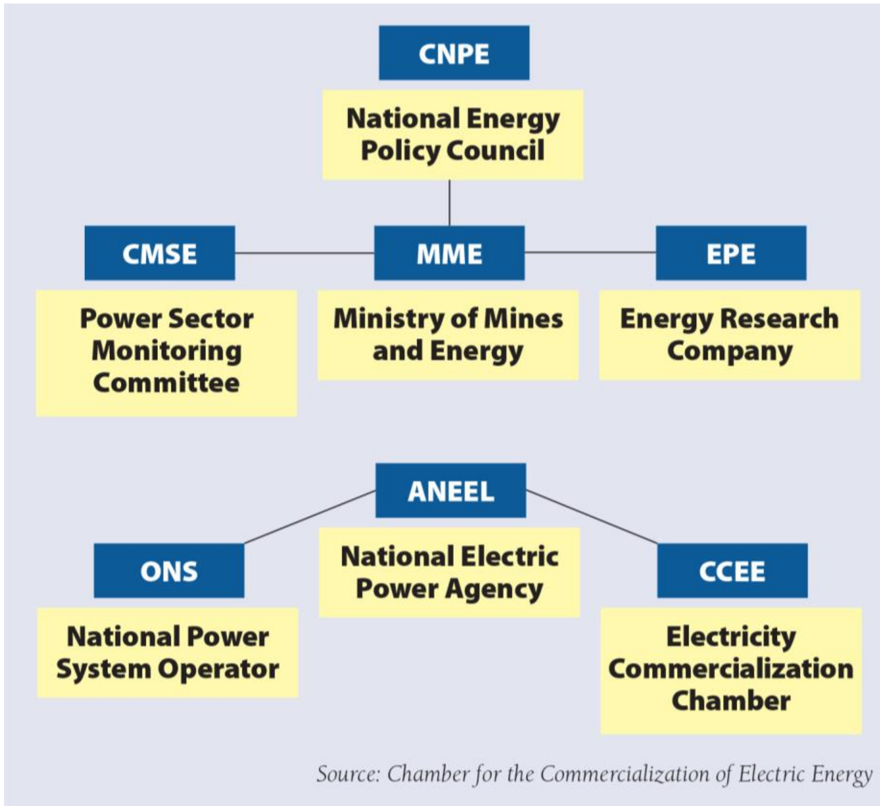
[169] IEA (2013). *World Energy Outlook*, p. 333.
[170] The majority of the material presented in this section is from two sources. The first is from Mauricio T. Tolmasquim's review of the Brazilian experience in *Power Sector Reform in Brazil* (2012). Dr. Tolmasquim, together with then-energy minister Dilma Rousseff and colleagues, were the architects for the latest round of reforms that took place in 2004. The second major source relied on was four chapters of the 2013 review of Brazil's energy sector in the IEA's *World Energy Outlook*.
[171] Tolmasquim, M. (2012). *Power Sector Reform in Brazil.* Synergia, p. 37.

Figure 16: Institutions Active in the Brazilian Electric Sector[172]



4.2 Power Sector Structure

The current model of the Brazilian electricity sector was adopted in 2004, building on earlier reforms that date back to 1993 and 1998. The model mixes public ownership with private investment, along with innovative mechanisms to promote competition. Generation, transmission, and distribution are unbundled. The reforms established two types of retail consumer: "captive" and "free." Residential and small commercial/industrial users — accounting for about 75 percent of the Brazil's electric consumption are captive — i.e., they are restricted to purchasing electricity from the distribution company in their geographic area. The free consumers, accounting for the remaining 25 percent of consumption, comprise approximately 40 large industrial and commercial customers who are permitted to contract directly with generators.[173]

[172] Sources: Chamber for the Commercialization of Electric Energy, retrieved from http://www.ons.org.br/institucional_linguas/relacionamentos.aspx?lang=en; Mercados (2013), *Current Practices in Electricity Transmission*, retrieved from http://www.raponline.org/document/download/id/6933; and Tolmasquim, 2012.

[173] Consumers are eligible to be "free consumers" if they have load of 3 MW or more and connect at voltages of 69 kV or more; however, new consumers with loads greater than 3 MW or more (i.e., those that connected after July 7, 2005) are not subject to the voltage constraints. Customers that meet these threshold requirements may optionally purchase services on a regulated basis. "Special consumers" are a set of consumers that form a common group with loads of 500 kW or more that contract energy that comes from solar, wind, and biomass receiving incentives. See Tolmasquim, 2012, p. 7-72.

Long-term purchase power agreements (PPAs) between distribution companies and generators are at the heart of Brazil's power sector model. [174] Each distribution company is responsible for forecasting medium-term demand growth for the captive consumers in its geographic area. Auctioning of long-term contracts for new generation capacity is overseen by government authorities to ensure that it is centralized, standardized, and transparent. This is an important mechanism for promoting low-cost expansion of a system that is undergoing rapid growth. Prices set at auction are passed on to end users. The PPAs provide a financial hedge, for both suppliers and purchasers, against price variations. By 2013, 24 auctions for generation had taken place, with some limiting participation to certain technologies (to promote resource diversification), amounting to 65 GW and total investment of about $120 billion.[175] Two all-source auctions were held in 2013. The first auction resulted in all awards going to 39 wind projects, slated to start in 2016. A second auction, calling for 325.6 TWh in 2018, also resulted in renewable energy generation having the winning bids. They consisted of five biomass plants, 16 small hydro plants, and 97 wind energy projects. Pricing of wind power in Brazil has steadily decreased, from $85/MWh in 2009 to $53/MWh in 2013.[176]

The PPAs determine who will supply power, the amounts to be purchased, and the prices to be paid. They do not, however, determine how the system will actually be operated. This is handled by an independent entity, the National Power System Operator (ONS), which optimizes (i.e., minimizes the total operating cost) of the electricity system through centralized dispatch of generation.[177] The wholesale market, then, is primarily a bilateral contract market. Yet the system is dispatched to optimize the value the resources (least-cost dispatch) subject to system constraints. When actual production and consumption do not match contractual obligations — as they almost never do — the market operator, CCEE, settles the differences at the Imbalance Settlement Price (PLD), which is in the short-term energy market.[178] (See below for more detail on generator dispatch.)

In addition to the trading to secure resource commitments (backed by physical resources), there is also a market for energy reserves. The amount of energy needed as a required reserve is determined by the Ministry of Mines and Energy based on studies conducted by the Energy Research Office (EPE). The costs of maintaining the energy reserve are covered through an Energy Reserve Charge that is collected from all users of the Brazilian power system.

[174] See Maurer and Barroso, 2011, and Azuela, et al., 2014.

[175] IEA, 2013.

[176] The Oxford Institute for Energy Studies (2014, August). *Sustainable Energy in Brazil: Reversing Past Achievements or Realizing Future Potential*. Retrieved from http://www.oxfordenergy.org/2014/08/sustainable-energy-in-brazil-reversing-past-achievements-or-realizing-future-potential/.

[177] The system operator performs functions that are critical to the smooth operation of the system. Mechanisms were created to ensure its independence from private parties and agents, in addition to government. See Tolmasquim, 2012, p. 41.

[178] The Imbalance Settlement Price reflects what is known as the marginal operations cost (CMO), which is a weekly proxy of a market clearing price. See Tolmasquim, 2012, p. 107.

4.3 Power Sector Planning

The purpose of planning in the sector is to ensure that the generation and transmission system keep pace with demand and maintain system reliability. High quality service at lowest cost are overarching objectives of the planning efforts. Environmental impacts and multiple uses of water also affect the planning efforts in multiple ways. Overall, the Brazilian planning process has been fairly successful and reasonably transparent, although (as with the other regions discussed in this paper) there is still scope to lower costs by better integrating end-use energy efficiency resources into the process.

Planning is the responsibility of EPE, which is responsible for conducting studies and projects that provide technical support for energy planning activities. Various market, generation, transmission, and environmental studies underpin the preparation of the Ten-Year Energy Expansion Plan and the Transmission Expansion Plan.[179] Supporting studies, including the market forecast and load projections are developed by EPE.[180] Five-year horizon projections involve collaboration between EPE and the ONS.

For planning purposes, the transmission system in Brazil is organized into two systems, the National Interconnected System (SIN), covering most of the country, and the isolated systems that are found in northern Brazil. Brazil's existing transmission network is relatively old, and subject to high transmission and distribution losses, at 16–17 percent.[181] The losses are not only technical but also encompass energy theft and measurement errors. ANEEL is focusing on reducing these losses in its annual tariff reviews.[182]

Expansion of the transmission system is handled through reverse auctions. The concessions are awarded for 30 years with opportunities for extensions. Between 1999 and 2010, 15 auctions were held, which resulted in 67 projects and a total of 21,317 kilometers of transmission lines. Nearly 14,000 of the 18,000 kilometers of transmission lines projected for 2015 are behind schedule.[183] A need for 42,500 kilometers of new transmission lines is forecasted for 2020.[184] The government issued a 10-year transmission plan intended to add more than 50,000 kilometers of transmission between 2013 and 2022. Transmission losses could drop from 17.3 percent to 16 percent.[185]

Brazil has more than 120 GW of generation capacity, of which some 68 percent is hydroelectric. There are nearly 900 hydro facilities, ranging in size from the very large to the very small, on Brazilian rivers. The total hydro capacity of 84 GW is second only to China in terms of installed hydro capacity in the world. The remainder are renewables (primarily wind, solar, and bioenergy facilities), fossil-fuel thermal plants, and nuclear facilities. Figure 17 describes expected generation resource additions in Brazil from 2013 to 2020 and projections to 2035.

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179 Among the more noteworthy studies prepared by the ENE are the Ten-Year Energy Expansion Plan (PDE), the National Energy Plan (PNE), the National Energy Balance (BEN), and the transmission segment planning studies that result in the Transmission Expansion Plan (PET). See Tolmasquim, 2012, p, 46.

180 Tolmasquim, 2012, p. 93.

181 The Oxford Institute for Energy Studies, 2014.

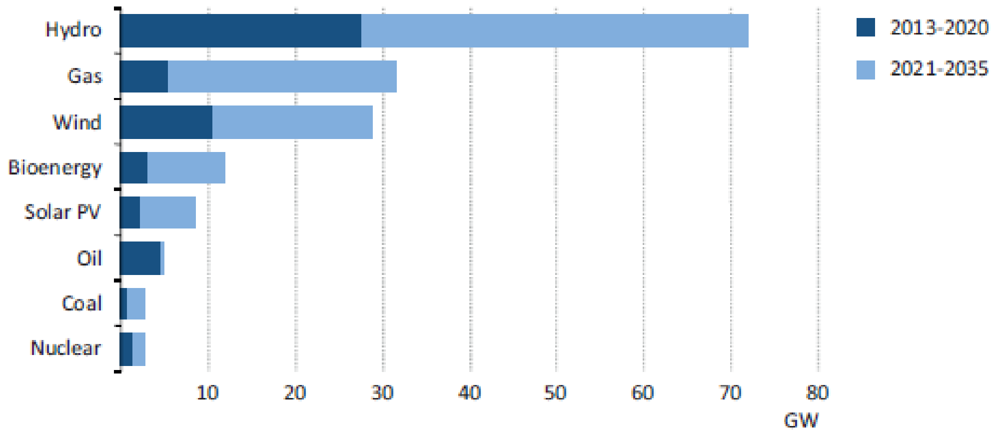
182 IEA, 2013.

183 The Oxford Institute for Energy Studies, 2014.

184 Tolmasquim, 2012, p. 82.

185 The Oxford Institute for Energy Studies, 2014.

Figure 17: Brazil Interconnected Generation Capacity 2013-20 and Projections to 2035[186]



Brazil has immense renewable energy resources that have not been fully utilized. The country has another 180 GW of hydropower and 350 GW of wind power potential. In addition, there is significant scope for expansion of biomass. Solar resources in Brazil are also considered to be vast.[187]

Figure 18 shows the energy production and the predominance of hydro as a source of generation. In addition to the low carbon footprint of the sector, due in large part to hydro, the significant reservoirs of Brazil give the Brazilian system a significant degree of flexibility, making the system an enabler of variable energy resources such as wind. Projections suggest that wind will be the fastest growing generation resource in percentage terms and the potentially the fastest growing capacity in absolute terms, over the near investment horizon.[188] Brazil expects to invest $14.9 billion in wind energy projects between 2015 and 2018 to increase total wind capacity to 7,227 MW. Currently, 202 wind projects are on-line, while another 378 are under construction.[189]

Low water years in 2012, 2013, and 2014 have simultaneously increased peak demand and reduced available water levels for hydropower. As a consequence, natural gas generation has rapidly increased, as it is being relied upon to balance the variations in hydro generation. In 2012, natural gas exceeded biomass as the second highest provider of electricity generation, at 8.5 percent.[190]

The long-term future of hydropower in Brazil is considered uncertain beyond 2035. Increasing public opposition to large hydro dams has prompted momentum towards run-of-river hydro projects and, as a result, hydro reservoir capacity is expected to increase by only 2 percent over the next decade. While preventing widespread flooding, run-of-river hydro facilities have little or no water storage, and their power output are more vulnerable to variations in rainfall.[191]

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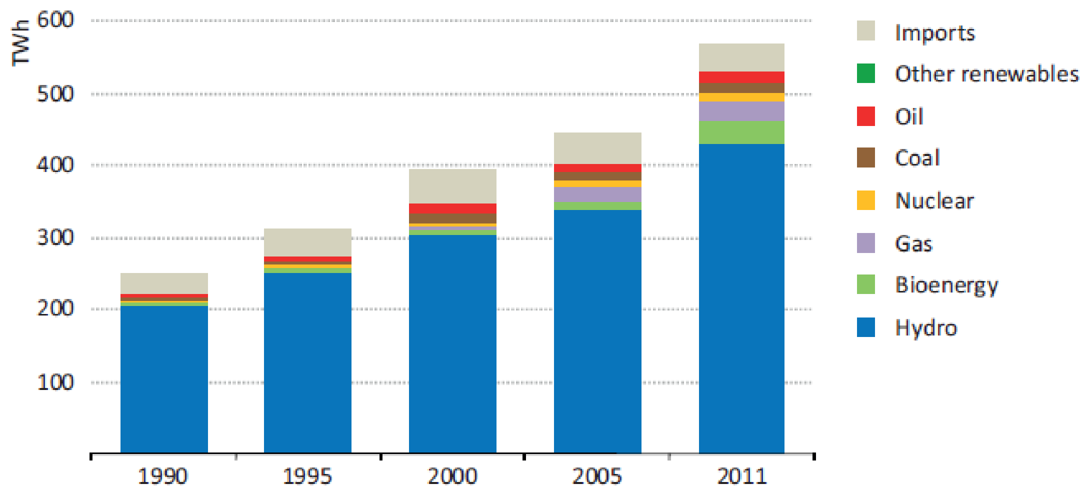
186 IEA, 2013.
187 The Oxford Institute for Energy Studies, 2014.
188 Sources: BNEF country profiles and Q4 2013 Wind Market Outlook; retrieved May 20,2014, from http://www.bnef.com; country profiles, downloaded on May 20, 2014 and BNEF, Q4 2013 Wind Market Outlook, December 2013, Bloomberg projects 8227 MW of wind energy capacity additions in 2014, 2015, 2016.
189 Global Post (2014). Brazil to invest $14.9 bn in wind energy between 2015 and 2018, September 9, 2014. Retrieved from http://www.globalpost.com/dispatch/news/agencia-efe/140909/brazil-invest-149-bn-wind-energy-between-2015-and-2018.
190 The Oxford Institute for Energy Studies, 2014.
191 The Oxford Institute for Energy Studies, 2014.

Figure 18: Energy Production 1990–2011



Source: BNEF

Only about 30 percent of the potential hydro capacity of the country has been tapped. Whether new or existing, the capacity or potential capacity of hydro is distant from loads. The Ten-Year Energy Expansion Plan 2020 calls for resource expansion by 56 percent, of which most will be provided by new hydro facilities. An important factor is whether hydro resources in the Amazon basin, which by itself accounts for 40 percent of Brazil's hydro potential, can be developed in the wake of socioeconomic and environmental concerns. Brazil plans to experiment with "platform hydropower" plants, intended to restrict development to the site itself and avoiding creation of worker housing, minimizing access roads, re-foresting impacted areas, and averting development of new villages or towns once construction is finished. The platform hydropower plant will be highly automated with a relatively small number of staff, comparable to offshore oil and gas platforms.[192]

Risks of power shortages from extended droughts of up to five years represent a major risk to be addressed through effective planning and resource diversification. As evidenced by the improvements to system planning, investment, and reliability of the last ten years, the system appears to be able to address these challenges.[193]

Through the Ten-Year Energy Expansion Plan, the EPE identifies transmission expansion requirements over the ten-year horizon. A series of reports focusing on the first five years forms the basis of the Transmission Expansion Plan. Through the Expansion and Reinforcement Plan (PAR), ONS is responsible for proposing adjustments to the transmission facilities to meet the requirements of system operations. These plans are then combined and reconciled by the Ministry of Mines and Energy, resulting in the Tenders and Grants Plan, which is then implemented by the regulator, ANEEL.

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[192] IEA, 2013.

[193] However, in December 2007, during unusually dry conditions in the Northeast, the Power Sector Monitoring Committee — created to monitor service conditions — took emergency measures to effectively overrule the dispatch model. The changes led to some alterations on the system. See Melo, E. and da Costa, A., *The New Governance Structure of the Brazilian Electricity Industry: How it is possible to introduce market mechanisms?*

4.4 Energy Efficiency Resources: Acquisition, Pricing, and Funding

There is extensive involvement in energy efficiency by both the federal government and ANEEL. The federal government has funded extensive energy efficiency programs through the partially state-owned electricity utility, Eletrobras.[194] The electricity regulator has imposed progressively more stringent energy efficiency obligations on electricity distribution utilities.

Federal government involvement in energy efficiency commenced in 1985 with the implementation of an electricity conservation policy (Administrative Directive Number 1877) that resulted in the establishment by the federal government of the National Electrical Energy Conservation Program known as PROCEL (Programa Nacional de Conservação de Energia Elétrica). Originally, PROCEL was managed within Eletrobras. In 1991, PROCEL was transformed into a government program coordinated by the Ministry of Mines and Energy but it still depends on resources from both Eletrobras and a federal loan fund, the Global Revision Reserve (RGR). Eletrobras manages the funds from the RGR.[195] Further funds are sought from international organizations to expand the activities of PROCEL. PROCEL funds or co-funds a wide range of energy efficiency projects focused mainly on: research, development and demonstration; education and training; testing, labeling and standards; marketing and promotion; private sector support; utility demand-side management programs; and direct implementation of efficiency measures.[196]

Guidelines for energy services companies (ESCOs) were established in Brazil in 1990. ESCOs were to be funded according to the savings obtained from energy projects, through their own funding, or with third party funds. However, even today, most ESCOs in Brazil are small businesses with fewer than 10 employees and overall revenue of under USD 1.13 million. There are some mid-sized companies with revenue of over USD 5.67 million and more than 20 employees, and also engineering firms that provide services in the area of energy efficiency. Few, however, are capable of carrying out the expected activities, due to limitations to investment financing. The main source of funding for ESCOs is the National Bank for Economic and Social Development, and to secure long-term financing, ESCOs must prove to be financially sound, and show potential for growth.[197]

Also in 1990, aiming to propose, implement, and monitor effective measures for the rational use of electric energy, and to control and disseminate the most relevant information, the government introduced legislation to establish Energy Conservation Intern Commissions (CICEs) in all government agencies. In 1993, an Executive Group for the Rational Production and Use of Energy (GERE) was established to oversee the CICEs. However, no funding was provided for the CICEs and no specific goals were established, so there was no effective GERE oversight. The members of each CICE sought to independently maintain optimal energy conservation in their respective area, setting targets of their own, without supervision by a government agency and with no guarantees of success.[198]

[194] Eletrobras is the majority-state-owned (52 percent) utility responsible for 38 percent of Brazil's generation, most of its transmission (either directly or as part of a consortium), and six of the smaller distribution companies.
[195] Lees, 2010.
[196] Szklo, Schaeffer, Schuller, and Chandler, 2005.
[197] De Oliveira, Shayani, and De Oliveira, 2013.
[198] Ibid.

In 1994, concession contracts for privatized electricity distribution utilities contained clauses that obliged the utilities to invest in energy efficiency and R&D activities. However, these contractual clauses were often too generic and hard to monitor; therefore it was difficult for the relevant authorities to verify utilities' performance.[199] In 1998, at the urging of PROCEL, the regulator, ANEEL, established a rule which defined more clearly arrangements for mandated utility programs, including the amount of annual investment, and procedures for submission, approval and verification of the programs. The rule required privatized electricity distribution utilities to allocate at least one percent of their revenues (about $170 million a year) to energy efficiency enhancement measures.[200] Of this amount, only half goes directly to fund energy efficiency. In effect this is a mandatory public benefits charge. Distribution utilities that were still state-owned were also required to contribute to the public benefits fund when their concessions were renewed. Beginning in 2000, generation and transmission companies also had to contribute but none of the public benefits charge revenue from these companies is allocated to energy efficiency.[201] The obligation on utilities was codified in Law No. 9,991 of July 24, 2000.

In 2001, an Energy Efficiency Law was passed by the Brazilian Congress (Law No. 10,295 of October 17, 2001). This Law provided for a National Policy for the Conservation and Rational Use of Energy. The Law allows the government to set minimum energy performance standards for products marketed in Brazil, either manufactured locally or imported, after public hearings involving the interested parties. The Law also mandates the government to promote energy efficiency measures in buildings. Progress in implementing the Energy Efficiency Law has been slow: energy efficiency standards have only been established for a few types of appliances and equipment.[202]

In 2011, the Brazilian Ministry of Mines and Energy published the National Energy Efficiency Plan. The plan calls for a reduction in energy consumption of around 10 percent by 2030, equivalent to savings of 106 TWh, and would avoid 30 million tons of carbon dioxide emissions in that year. The plan also involves replacing 1 million old refrigerators per year for 10 years. Lastly, the plan aims to improve energy efficiency in industry, transport, and buildings.[203]

In 2012, ACEEE reviewed the energy efficiency performance of 12 of the largest economies in the world. Despite the progress in residential buildings and appliance labelling, Brazil scored in the bottom quarter of the countries listed, just below the US and China, but above Canada and Russia.[204] Brazil is achieving only a small share of the energy efficiency potential from ESCOs and is well behind China and the United States in developing shared savings contracts for industry.[205]

199 Jannuzzi, 2005.
200 Szklo et al., 2005.
201 Taylor, Govindarajalu, Levin, Meyer, and Ward, 2008.
202 De Oliveira et al., 2013.
203 International Partnership for Energy Efficiency Cooperation, 2012.
204 Hayes, S., et.al. *The ACEEE 2012 International Energy Efficiency Scorecard,* ACEEE, Report E12A. Retrieved from http://www.aceee.org/sites/default/files/publications/researchreports/e12a.pdf.
205 BNEF (2013). *Energy Efficiency in Brazil, Tantalizingly Out of Reach*, December 13, 2013.

Table 3: Investments in and Savings from Energy Efficiency in Brazil, 1986–2009[206]

Year	Investment disbursements [ªUS$ million]	Total consumption [TWh]	Avoided investment [ªUS$ million]	Peak demand reduction [MW]	Energy saved	
					[TWh]	[% of total consumption]
1986–1999	298.08	3507	1809.96	2719.00	9.00	0.26
2000	14.71	332	1131.22	552.00	2.30	0.69
2001	16.97	310	1187.78	600.00	2.50	0.81
2002	23.76	324	735.29	309.00	1.30	0.40
2003	23.19	360	1131.22	453.00	1.30	0.36
2004	53.17	375	1404.03	622.00	2.40	0.64
2005	55.43	390	1018.10	585.00	2.20	0.56
2006	63.91	412	1244.34	772.00	2.80	0.68
2007	29.98	428	1583.71	1357.00	3.90	0.91
2008	17.53	426	1644.23	1588.00	4.30	1.01
2009	36.71	443	2213.56	2098.00	5.47	1.23
Total	**633.44**	**7307**	**15,103.44**	**11,655.00**	**37.47**	**0.51**

ª US$1.00 = R$1.77 on 10/03/2010.

4.4.1 Use of the Public Benefit Funds

The allocation of public benefits charge revenues among different programs and types of applications is subject to regulations established by ANEEL, which also approves utility project proposals for use of these funds and oversees compliance. Utilities are responsible for designing and executing all their own programs and projects. ANEEL revises annually the criteria for approving utility programs. In 2013, ANEEL drafted a new set of regulations for utility energy efficiency programs, using results from studies conducted by EPE. In these regulations, ANEEL specifies the criteria for utilities to follow when investing their statutory share of the public benefits charge (approximately $170 million a year) in energy efficiency projects.[207]

The allocation of revenues has changed very significantly since the initial implementation of the public benefits charge in 1998, and the Brazilian Congress has since passed several laws that impact the specifics of the public benefits charge program. While the total obligation has remained at one percent of utility revenue, the proportion allocated to energy efficiency programs has varied from 0.25 percent to 0.9 percent. A 2007 law passed by the Brazilian Congress reinstated the energy efficiency allocation to 0.5 percent, half of which must be spent on energy efficiency measures targeted at low-income households.[208] (The charge is changing back to 0.25 percent on January 1, 2016.)[209] A small proportion (about 0.1 percent) is also used to support the activities of EPE.

In the initial phase, utilities could allocate up to 0.65 percent of the 0.90 percent for energy efficiency to "supply-side" measures, thereby reducing their technical and commercial losses. The legislation of 2000 codifying the obligation on utilities, restricted applications to end-use measures. Utility programs for education on electricity saving and municipal energy management are also eligible. This change was more consistent with the objectives of the public benefits charge since, in the newly liberalized electricity industry, utilities already have strong incentives to reduce their losses.

[206] De Oliveira et al., 2013.
[207] GIZ, 2014.
[208] Taylor et al., 2008.
[209] Source: ANEEL Manual 2012, retrieved from http://www.aneel.gov.br/arquivos/PDF/Manual-PeD_REN-504-2012.pdf.

Over time, successive rounds of rulemaking by ANEEL gradually restricted utilities' options and came to require maximum cost-benefit ratios from the utility perspective for energy efficiency projects (0.80 for most projects, 1.00 for public lighting projects). This requirement focused utility energy efficiency activity on projects that were not cost-effective to the utility but provided benefits to society as a whole. Use of public benefits charge revenue for marketing was eliminated and utilities were required to implement minimum allocations of funding to each economic sector. These allocations were the same for all utilities, regardless of the large differences in the size and markets of different utilities. Initially energy efficiency projects had to be completed within a one-year cycle, but later rules allowed projects to be extended to more than one year.[210]

Table 4: Investments by Brazilian Utilities in End-Use Energy Efficiency, 1998–99 to 2003–04[211]

Cycle	No. of utilities	Total investments (US$ million)	% in end-use programs	Avoided demand (MW)	Energy savings (GWh)
1998–99	17	68.3	32	250	754
1999–2000	42	75.9	40	369	994
2000–01	53	35.4	94	n.a.	n.a.
2001–02	60	57.2	99	496	1,498
2002–03[a]	28	39.8	100	n.a.	n.a.
2003–04[b]	40	66.8	100	n.a.	n.a.

Initially, all projects were funded by grants to the utilities from the public benefits charge revenue. In later cycles, utilities were allowed to recover some of their energy efficiency expenditures by using performance contracts with the owners of the facilities where the projects were implemented, excluding facilities in the education, municipal, or residential sectors. Part of the funds recovered by the utilities could be used for new energy efficiency projects, and part to reduce electricity prices for consumers.[212]

Table 4 summarizes the investments by Brazilian utilities in end-use energy efficiency in the annual cycles since 1998–99 and 2003–04, as well as the estimated energy savings and avoided system demand. The annual cycles do not follow calendar years. The investment values since 2002 are estimates, since official figures were not disclosed. The estimates of avoided demand and energy savings are even patchier, since there was little if any systematic verification of the results. Investments through the public benefits charge were about five times greater than investments by PROCEL, which amounted to $70 million during the same time period.[213]

210 Taylor et al., 2008.
211 Ibid.
212 Ibid.
213 Ibid.

4.5 Renewable Energy Resources: Acquisition, Pricing, and Funding

In Brazil, renewables, dominated by hydropower, account for a relatively high share of electricity generation capacity: 80 percent of the country's more than 120,000 MW of installed capacity.[214] Due to a combination of its large size and strong policies, Brazil has also emerged as a leader in wind, biomass and solar power development.

In 2002, Brazil launched a major initiative to promote renewable energy sources (RES), the Program of Incentives for Alternative Energy Sources (PROINFA). The Program mandated that 3,300 MW of wind, small hydro, and biomass be brought on stream, through 20-year contracts, by the end of 2022. PROINFA acted much like a feed-in tariff, with producers receiving fixed prices based on the specific technology used. Brazil draws on an Energy Development Account, funded by end-use customers, to pay for PROINFA's system of subsidies and incentives.[215] When PROFINIA was terminated in 2011, 2.6 GW of capacity was developed, consisting of small-scale hydro, wind and biomass.[216] Though plagued by implementation delays and efforts by companies to game the payment system, PROINFA is credited with starting renewable energy business development in Brazil.[217,218]

Today, technology-specific auctions of long-term contracts to build generation capacity (as discussed above) are Brazil's primary mechanism for promoting renewable energy development. In Brazil's regulated markets — which represent about 75 percent of electricity demand — generators must sell electricity directly to distribution companies through auctions. In turn, distribution companies must purchase enough generation power to ensure that their users' demand is fully met. Auctions are held for existing energy sources, new energy sources, and reserve energy. Within the latter two categories, individual auctions are targeted at specific renewable sources, such as wind or biomass. Brazil's technology-specific auctions appear to be accelerating renewable energy development. As of February 2014, for example, Brazil was on track to reach 10 GW of wind capacity by 2017 — eight years ahead of the country's original plan.[219] Brazil's next auction, scheduled for 31 October 2014, will include a separate category for solar. About 400 projects have registered, representing 10.79 GW. Solar companies will compete for 20-year contracts for projects of at least 5 MW that must be completed by October 2017.[220]

Brazil uses loans to further promote renewable energy development. Developers and manufacturers can tap the Brazil Development Bank for loans to buy or make turbines, assuming they meet local-content requirements that have increased over time.

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[214] Branco, A. (2013). *Renewable Energy Brazil* [Presentation]. PwC, April 2013. Retrieved from http://brazilianchamber.org.uk/sites/brazilianchamber.org.uk/files/Castello%20Branco.pdf.

[215] IEA/IRENA Joint Policies and Measures database. Retrieved from http://tinyurl.com/pugc3rh**.**

[216] The Oxford Institute for Energy Studies, 2014.

[217] Assunção, J., Chiavari, J., and Szerman, D. (2014). Misreporting in Wind Power Contracts. Climate Policy Initiative, May 2014. Retrieved from http://climatepolicyinitiative.org/wp-content/uploads/2014/05/Misreporting-in-Wind-Power-Contracts-Technical-Paper.pdf & Luiz Barrason, PSR, www.irena.org/DocumentDownloads/events/2012/November/Tariff/4_Luiz_Barroso.pdf.

[218] Luiz Barrason, L. (2012). Renewable Energy Auctions: the Brazilian Experience [Presentation at IRENA workshop]. PSR, November 2012. Retrieved from www.irena.org/DocumentDownloads/events/2012/November/Tariff/4_Luiz_Barroso.pdf.

[219] Navigant Research (2014). *Brazil Will Have More Wind Power Capacity Installed by 2022 Than All Other Latin American Nations Combined* [Press release], February 19, 2014. Retrieved from http://tinyurl.com/lnb5vo9.

[220] Dezem, V. (2014). Brazil's First Solar-Specific Power Auction Draws 10.8 GW of Interest, *Renewable Energy World*, July 30, 2014 Retrieved from. http://www.renewableenergyworld.com/rea/news/article/2014/07/developers-apply-for-10-8-gw-of-capacity-in-brazils-first-solar-specific-power-auction.

Currently, 60 percent of turbine components must come from local suppliers and at least three of four main elements — towers, blades, nacelles, and hubs — must be produced or assembled in Brazil. Compliance with these local requirements has been a challenge.[221]

In 2012, Brazil issued regulations to further support the growth of solar energy. These regulations offer utilities an 80 percent discount on taxes paid for distributing electricity generated by large solar projects. They also provide net metering options for homes and businesses with systems such as rooftop solar panels.[222,223] Meanwhile, a government credit program called Proesco has helped bring the cost of electricity from rooftop solar below the cost of electricity sold by 10 of the country's 63 power distributors.[224]

4.6 Renewable Energy Integration

The flexibility needed to integrate variable renewable energy production into Brazil's electric system is provided by the country's hydroelectric resources and nationwide transmission grid (that is, the large national balancing area). Hydroelectricity complements wind resources in the northeast and south, and bioelectricity in the southeast.[225] The high capacity factors of wind plants in Brazil also make integration easier, as variability is reduced. The seasonal pattern of wind production in northeastern Brazil, where most of the wind capacity is located, is a good counterpart to run-of-river hydro during the dry season. Biomass power also is a complementary resource, as the sugarcane harvest starts before the beginning of the dry season and continues past its end. Hydropower dams also help offset reduced production from run-of-river hydro during the dry season, as reservoirs can be refilled during times of high run-of-river hydro production.[226]

As demand for electricity continues to grow and new renewable energy sources are brought on line, the country is planning for new transmission facilities to be built. As mentioned above, Brazil uses a somewhat unusual — but generally effective — state-run auction process to meet these needs. After a particular need is identified (through the long-term transmission planning process), the National Energy Agency calculates a maximum "annual allowed revenue" for the project. An auction is then held in which bidders reveal the annual revenue that they will need over the lifetime of the transmission line (typically 30 years) in order to build and maintain it. The concession is awarded to the party that bids the lowest annual allowed revenue below the agency's pre-established cap. Annual allowed revenue payments are guaranteed by contract. Though cost-effective in theory, Brazil's adherence to using the lowest bidder has reportedly proven

[221] Nielsen, S. (2012). BNDES raises local content requirement for Brazil wind turbines, Bloomberg News, December 13, 2012. Retrieved from http://www.bloomberg.com/news/2012-12-13/bndes-raises-local-content-requirement-for-brazil-wind-turbines.html.

[222] Nielsen, S. (2012). Brazil to issue regulations supporting solar energy, ANEEL says. *Bloomberg News*, March 14, 2012. Retrieved from http://www.bloomberg.com/news/2012-03-14/brazil-to-issue-regulations-supporting-solar-energy-aneel-says.html.

[223] Thurston, C. (2012). Brazil laying foundation for new solar market. *Renewable Energy World*, April 2012. Retrieved from http://www.renewableenergyworld.com/rea/news/article/2012/04/brazil-laying-foundation-for-new-solar-market.

[224] Bloomberg News (2012). Brazil solar energy, at $299 a megawatt hour competes with grid, July 3, 2012. Retrieved from http://www.bloomberg.com/news/2012-07-03/brazil-solar-energy-at-299-a-megawatt-hour-competes-with-grid.html.

[225] Barrason, 2013.

[226] IEA, 2013.

counter-productive at times, because companies with questionable construction practices often underbid more professional competitors.[227]

4.7 Generator Dispatch

Brazil's approach to dispatch and generation compensation has some interesting and unusual features, but, at its core, it is characterized by the same essential elements as systems in the other regions: dispatch that minimizes total operating cost by adhering to the marginal-cost merit order, with at least an implicit recognition (through policies favoring renewable resources or setting emissions performance standards) that environmental damage is a marginal cost of production.

As described earlier, all electricity in Brazil is covered under purchase power agreements (PPAs). The PPAs describe the commercial relationships between buyers and sellers, in particular how much electricity will be provided and at what prices will it be purchased. They do not, however, determine how the system actually operates.

The independent ONS is responsible for the real-time operations of the Brazilian power grid. This entails planning and scheduling the centralized dispatch and operation of generation, supervising and coordinating the activities of the power system operations centers, managing transmission service, and providing ancillary services.

The owners of generation cede operational control of their facilities to ONS, which then operates them according to the rules of economic, or merit order, dispatch — that is, in order of increasing marginal (primarily variable fuel) cost — in the same way systems in the US and Europe are operated.

Declarations of the marginal costs of all facilities on the system are provided to ONS by the generation owners); they determine the plants' dispatch order (the dispatch "stack"). Zero marginal cost facilities, typically hydroelectric and other renewable energy facilities whose output cannot be controlled ("must-take" resources) are dispatched first, followed next by low-cost dispatchable generation, and then by progressively more costly plants as demand increases. As demand falls, plants are taken off line in the reverse order. The system's total operating cost in minimized in this way, because, as a general rule, at no time is a plant operating whose marginal cost is greater than any plant that is idle.

4.8 Carbon Pricing

Energy represents a minority of Brazil's overall carbon emissions: only 32 percent of green-house gas emissions in 2011, second to agriculture. Improvements in land-use and forestry practices have improved the contribution of that sector from 2005 to 2011. Figure 19 shows the sources of greenhouse gas emissions in Brazil. While Brazil has a larger economy than Russia, its contribution to green-house gas emissions is only one-quarter that of Russia's.[228] Brazil issued a National Plan on Climate Change in 2008, and an updating process was initiated in 2013.[229]

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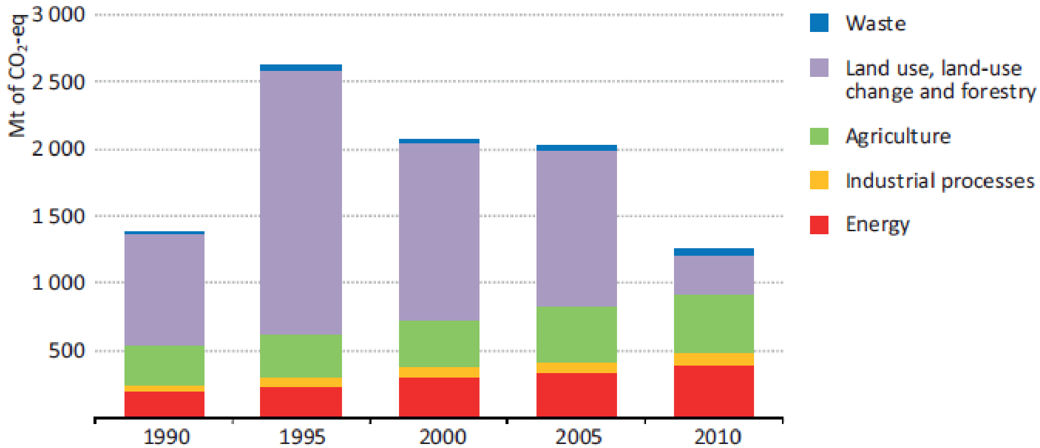
[227] Salcedo, F. and Porter, K. (2013). *Regulatory Framework and Cost Regulations for the Brazilian National Grid*, Montpelier, VT: Regulatory Assistance Project, September 2013. Retrieved from www.raponline.org/document/download/id/6962.

[228] IEA, 2013, p. 318.

[229] See Government of Brazil's National Plan on Climate Change, retrieved from http://www.mma.gov.br/estruturas/imprensa/_arquivos/96_11122008040728.pdf, and Partnership for Market Readiness country profile, retrieved from https://www.thepmr.org/country/brazil-0.

A framework for carbon pricing has yet to be implemented in Brazil, although EIA's World Energy Outlook highlights the intent to establish a carbon pricing framework for unspecified sectors in Brazil.[230]

Figure 19: Brazil Greenhouse Gas Emissions by Source[231]



Source: Ministry of Science and Technology (2013).

4.9 Current Issues and Concluding Comments

Brazil faces the challenges of identifying, building, and integrating a cost-effective mix of resources in the context of rapid economic growth. Brazilian policymakers are anxious to have adequate resources and a reliable power system in order to avoid power crises like those the country experienced in 2001-02. Meanwhile, Brazil's power sector emissions — historically low due to the large share of hydro resources — have been rising more rapidly than those of other sectors of the economy. The country's stated goals include promotion of energy efficiency, maintaining the large share of renewables in the electricity resource mix, and reducing losses in transmission.[232] Achieving these goals will require a stronger and more cohesive policy framework, including better integration of demand-side resources.

There are several important resource challenges that have yet to be fully addressed. First, energy efficiency, as we have seen, is a resource that is not comprehensively exploited in Brazil's power sector.[233] A major challenge is ramping up energy efficiency programs in order to achieve Brazil's resource adequacy and emissions reduction goals. So far, only supply-side options have been allowed to compete in the auctions for contracts to supply power system resources. Policymakers have discussed allowing energy efficiency resources to compete in future auctions. This is a promising idea and could, if well designed, demonstrate energy efficiency's advantages as a reliable and low-cost resource, although it remains to be seen whether and how such auctions will be implemented. A related question is strengthening of the requirement for utilities to spend a fraction of their operating revenues on energy efficiency, which is currently only 0.5 percent.

[230] IEA, 2013, p. 50.
[231] IEA, 2013, p. 310.
[232] See Government of Brazil's National Plan on Climate Change.
[233] Luomi, 2014.

Second, Brazil faces particular difficulties with its hydro system. Brazil's existing hydro facilities have significant reservoir capacity, which plays an important role in reliability and integration of renewables. There is growing concern about environmental damage from large hydro facilities. In order to reduce environmental damage associated with flooding, new hydro facilities are increasingly likely to be constructed as run-of-river, lacking reservoirs. In addition, there is a risk of changing rainfall patterns. In fact, 2013 and 2014 have been difficult years for hydro resources in Brazil.[234]

Third, as Brazil's domestic natural gas supplies expand, the share of renewables in the resource mix may be displaced. The IEA's 2013 *World Energy Outlook* sees Brazil's natural gas production rising from 18 billion cubic meters (bcm) in 2012 to 38 bcm in 2020, and 92 bcm in 2035.[235] To the extent that natural gas will displace hydro and wind rather than coal (which is not a prominent resource in Brazil), these new gas supplies will lead to increasing GHG emissions.

As we have seen in other countries, the answer to all of these questions will revolve around Brazil's ability to 1) implement a refined power sector planning process that considers a wide range of resources and resource attributes; and 2) achieve the targets and resource goals identified in low-carbon planning processes. As we have discussed, Brazil has several strong points in these areas, including well-designed auctions for supply-side resources. However, there will be continuing debates about how to refine these policies.

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5. Low-Carbon Power Sector Regulation: Conclusions and Implications for China

The power sector accounts for more than half of annual coal consumption in China. The government has set a number of goals to reduce carbon emissions and coal consumption, and also has set closely related goals to improve air quality. These are described in the *12th Five-Year Plan (2011–2015)* and the *Air Pollution Prevention and Control Action Plan (2013–2017).* In addition, many provinces and municipalities have set very ambitious 2017 goals for coal consumption reduction and air quality improvement. Transformation of the power sector will be an important part of meeting these goals.

This paper has surveyed power sector regulation in the United States, European Union, and Brazil, highlighting issues important for carbon emissions regulation. Although China has its own particular set of challenges and characteristics, the experience in these countries – both the successes and failures – is very relevant. This final section discusses implications of our findings for China.[236]

5.1 Various Power Sector Models can be Low-emission Models

The regions in this report vary in the degree to which they have "liberalized" the electricity industry by breaking up vertically integrated utilities and introducing competitive wholesale and retail markets. This has been the focus in the EU (although some parts of the EU have proceeded further down this road than others) and in some US states. However, we have seen that no matter what model is chosen, careful attention to regulatory issues is the key to lowering emissions from the power sector.

In the liberalized examples, power sector planning is still necessary in order to identify outcomes and ensure that markets are delivering the desired results. In other words, markets don't design themselves and must be carefully overseen – and, when necessary, modified – by regulatory agencies to ensure that policy objectives such as emissions reduction are being delivered. In the EU, the backdrop for discussions about market design is framed by long-term carbon and clean energy policy goals, high-penetration renewable scenarios, and studies analyzing the cost-effectiveness of energy efficiency.

More "traditional" power sector models can also very reliably and cost-effectively meet demand while at the same time lowering emissions; again, the key is effective regulation. As we saw, some US states that have maintained more-or-less traditional models are leaders in emissions reduction. Meanwhile, Brazil has designed and implemented an innovative set of mechanisms – featuring auctions of long-term contracts for construction of generation and transmission – that easily fits neither "liberalized" or "traditional" models, yet is effective at stimulating more renewable energy capacity in the context of a developing country's rapid demand growth and institutional constraints. The question for China is not necessarily how to liberalize the power sector, but how to take advantage of international best practices in regulation and to design a regulatory model that is best suited to China's needs and character and meets China's long-term efficiency and environmental goals at low cost and low risk.

[236] See also Regulatory Assistance Project, 2013.

5.2 Energy Efficiency as a Power Sector Resource

We have seen how regulatory agencies take responsibility for guiding and influencing power sector resource profiles through transparent, analytically sophisticated, and broad-based planning processes. In the best examples, demand-side resources (particularly end-use energy efficiency) are very much the responsibility of regulatory agencies, planners, and utilities. We discussed examples where regulatory agencies require end-use energy efficiency to be considered as a resource on an equal basis with conventional generation, transmission, and distribution resources – and sometimes even require energy efficiency to be treated as the “priority resource.” These requirements and regulations have been based on strong — indeed, incontrovertible — evidence that energy efficiency is a plentiful and low-cost resource that can be a powerful tool for cost savings and emissions reductions. China already has a very good set of policies for promoting energy efficiency across the economy, including the “Top 10,000” program, the energy conservation supervision system, and various codes and standards. Integrating this long-standing commitment to energy conservation into a well-designed power sector plan that considers all costs and benefits of various resource options, including energy efficiency, would likely highlight many further opportunities to displace coal plants and reduce emissions.

We discussed many examples of governments placing obligations on utilities and electricity distribution companies to deliver end-use energy savings — and we also discussed the well-verified and cost-effective results. In China, the “Demand-Side Management (DSM) Measures Implementation Rule” of 2010 was an important first step in establishing an energy efficiency obligation for gridcos. However, there is much that can be done to 1) expand the obligation (from the current target of 0.3 percent of previous year’s sales and 0.3 percent of maximum demand); 2) focus it on end-use energy efficiency (as opposed to internal gridco energy savings); and 3) improve evaluation, monitoring, and verification of the DSM investments.

Finally, we discussed the interaction between utility regulation and the utility’s motivation to support end-use energy efficiency programs. China can benefit from the lessons learned — particularly in the United States — regarding regulatory incentive mechanisms for utilities that change electricity sales from being the sole measure of utility performance to include other factors such as delivery of energy savings. A first step is to improve the transparency of the finances of gridcos and other firms in China’s power sector, and study the links between gridco revenue and end-use energy efficiency. After that, incentive mechanisms may be designed to adjust gridco motivations and performance.

5.3 Managing Variable Renewables and Supporting Resources

We have also explained how the three regions are all grappling with the challenge of planning for, and integrating, increased levels of variable renewables into the power system and of the attendant need for more flexibility from other resources. China has had great success in mobilizing investment to rapidly expand power sector resources. However, challenges remain, particularly with integrating renewables into the grid.

Drawing on the international experience, there are a number of measures that could be taken in China:

- Adopt a stronger locational element to FITs to encourage greater geographic diversity for renewables.
- Include, to a greater degree, transmission and location considerations when considering proposed wind projects. Transmission should be considered during the review of new generation proposals.
- Extract flexibility from existing generation to the extent possible, and restructure the generation price structure to compensate for that flexibility among existing and new plants. Flexibility is defined as generators being able to quickly start and stop electricity generation as well as to be able to ramp up and down quickly and to operate at low generation levels.
- Establish further compensation schemes for ancillary services.
- Adopt or improve existing grid codes, policies, and incentive mechanisms to encourage flexibility for new conventional and renewable generation.
- Cease the addition of inflexible plants in areas with high wind and solar potential.
- Share curtailment costs between grid companies and renewable generators, with a larger share of the burden born by grid companies. This recommendation will allow wind (and eventually solar) generators to be paid the FIT even if they are curtailed.
- Reduce the number of balancing areas, either virtually (through sharing reserves, for example) or through consolidation, and encourage more regional power transfers.
- Connect renewable generation more quickly and improve renewable generation siting through clear interconnection procedure and coordinated transmission planning.
- Improve and make better use of wind forecasts.
- Adopt faster generation scheduling and dispatch practices.
- Implement priority dispatch for renewables.

Together, these should greatly improve the flexibility of the system and provide better incentives for the grid companies and other players to support variable renewables.

5.4 Generator Dispatch

One of the clearest conclusions from this report is that China is unusual in its approach to generator dispatch. In all of the places studied in this report — and in fact in almost all of the other countries in the world — generators are dispatched to minimize variable operating costs, including any environmental costs that have been “internalized,” for example through emissions pricing.

In China, however, the government annually assigns target numbers of operating hours for the coal-fired generators, all roughly of the same magnitudes (i.e., 4,000–5,000 hours), and sets prices for their output that, given those targets, will produce revenues sufficient to cover the generators’ total costs for the year. This is referred to as “equal shares dispatch.” This approach does not optimize the economics of system operations. Moving to dispatch based on generator variable costs will help reduce power sector emissions, not to mention produce other benefits: reduction of generator investment, fuel, and maintenance costs; better integration of renewable energy; and improved system reliability. These benefits will be bolstered further if the variable costs used for dispatch include not just direct generator costs but also environmental and emissions costs.

Of course, this is not a new topic in China: the government has piloted dispatch reforms in certain provinces, but these have not been widely implemented. An important obstacle to improved dispatch is the pricing scheme for wholesale electricity in China, alluded to above, which lumps together fixed and variable costs. A possible reform would be establishment of a two-part pricing scheme so that generators earn (1) a capacity price paid in RMB per kW per year, tied to generator availability, and (2) an energy price (reflecting short-run variable — mostly fuel — costs) paid in renminbi per kWh, tied to generator output.

5.5 Integrating Carbon Pricing with Other Emission-Reduction Policies

We have discussed how emissions trading schemes are increasingly designed to be well-integrated with other policies, particularly energy efficiency programs. This is because of the difficulty of relying on emissions prices alone to stimulate investment in energy savings and other clean energy resources. In practice, energy consumers are typically not very responsive to changes in prices and therefore it takes large increases in price to stimulate even modest investments in energy efficiency. Pairing emissions trading schemes with programs that mobilize capital for direct, comprehensive investment in energy efficiency has worked well. These efficiency programs may be administered by government agencies, government-affiliated organizations, or grid companies. The emissions trading scheme in the northeastern US, which focuses on the power sector, is a particularly useful example. In this scheme, emission allowances are auctioned and the revenue is used to support end-use energy efficiency programs (mostly of the type run by utilities, as described above).

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