Market Evolution: Wholesale Electricity Market Design for 21st Century Power Systems

Jaquelin Cochran, Mackay Miller, Michael Milligan, Erik Ela, Douglas Arent, and Aaron Bloom
National Renewable Energy Laboratory

Matthew Futch
IBM

Juha Kiviluoma and Hannele Holtinnen
VTT Technical Research Centre of Finland

Antje Orths
Energinet.dk

Emilio Gómez-Lázaro and Sergio Martín-Martínez
Universidad de Castilla La Mancha

Steven Kukoda and Glycon Garcia
International Copper Association

Kim Møller Mikkelsen
Global Green Growth Institute (GGGI)

Zhao Yongqiang and Kaare Sandholt
China National Renewable Energy Center

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21st Century POWER PARTNERSHIP
Accelerating the transformation of power systems

CLEAN ENERGY MINISTERIAL
Accelerating the Transition to Clean Energy Technologies

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NOTICE

Abstract

Demand for affordable, reliable, domestically sourced, and low-carbon electricity is on the rise. This growing demand is driven in part by evolving public policy priorities, especially reducing the health and environmental impacts of electricity service and expanding energy access to underserved customers. Consequently, variable renewable energy resources comprise an increasing share of electricity generation globally. At the same time, new opportunities for addressing the variability of renewables are being strengthened through advances in smart grids, communications, and technologies that enable dispatchable demand response and distributed generation to extend to the mass market. A key challenge of merging these opportunities is market design—determining how to create incentives and compensate providers justly for attributes and performance that ensure a reliable and secure grid—in a context that fully realizes the potential of a broad array of sources of flexibility in both the wholesale power and retail markets.

This report reviews the suite of wholesale power market designs in use and under consideration to ensure adequacy, security, and flexibility in a landscape of significant variable renewable energy. It also examines considerations needed to ensure that wholesale market designs are inclusive of emerging technologies, such as demand response, distributed generation, and distributed storage. The report concludes with a review of potential areas for future research on wholesale power markets.

Well-designed markets encourage economically efficient solutions, promote innovation, and minimize unintended consequences. Yet, many uncertainties remain about how to achieve these aims in power markets, given the need to accommodate contextual constraints and effectively invite and sustain capital investments. There is an acute need for international collaboration on wholesale market design questions. The 21st Century Power Partnership aims to provide a platform for collaborative analysis, and the authors of this report sincerely hope that it lays the groundwork for future collaboration.

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List of Acronyms

CAISO	California Independent System Operator
CFE	Comisión Federal de Electricidad
DSO	distribution system operator
ELCC	effective load-carrying capability
ERCOT	Electric Reliability Council of Texas
EU	European Union
FERC	Federal Energy Regulatory Commission
ISO	independent system operator
ISO-NE	ISO New England
LMP	locational marginal price
LOLP	loss of load probability
LSE	load-serving entity
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
PJM	PJM Interconnection
PV	photovoltaic
RAP	Regulatory Assistance Project
RTO	regional transmission organization
TSO	transmission system operator

Executive Summary

Wholesale electricity market designs represent both a challenge and an opportunity for realizing 21st century power systems, in which variable renewable energy and emerging technologies such as smart grids, demand response, distributed generation, and distributed storage, are tightly integrated into power system operations. Wholesale electricity markets in restructured, competitive markets serve two roles: they define the security-constrained, merit-order dispatch that ensures short-term reliability, and they define the financial incentives and rules of eligibility for investment in resources that ensure long-term reliability. The continuing evolution of policy objectives and emergence of new technologies is dramatically changing the nature of wholesale market design. Fortunately, learning and expertise accumulated over recent history provides an indication of how electricity market design might evolve. This report summarizes the key issues and evolving approaches in the field, and looks ahead to the research areas and collaborations that will support further advances.

Toward 21st Century Power Systems

Demand for affordable, reliable, domestically sourced, and low-carbon electricity is on the rise. This growing demand is driven in part by evolving public policy priorities, especially of reducing the health and environmental impacts of electricity service and expanding energy access to underserved customers. Consequently, variable renewable energy resources comprise an increasing share of electricity generation globally. Expanding the grid penetration of resources with variable output requires more nimble power systems that can adjust quickly to balance supply and demand. At the same time, new opportunities for addressing the variability of renewables are being strengthened through advances in smart grids, communications, and technologies that enable dispatchable demand and distributed generation to extend to the mass market. Figure ES-1 illustrates the range of dynamic interactions that might characterize 21st century power systems.

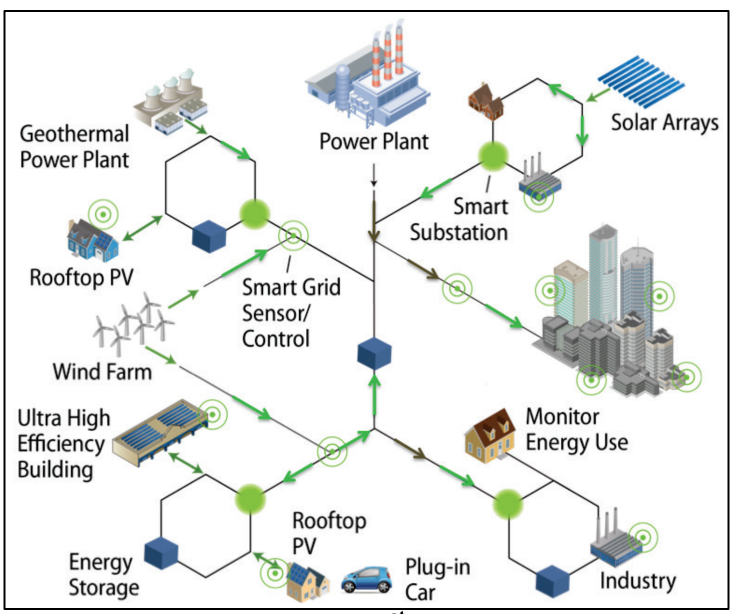

Figure ES-1. Illustrative view of 21st century power systems. *NREL*

Wholesale Market Design Principles for Integrating Variable Renewable Energy

Broadly speaking, there are three paradigms in use around the world to organize electricity delivery. In some regions utilities operate under the traditional vertically integrated utility model—the first paradigm. In these regions, most or all assets are owned and operated by a single entity, and costs are recovered through a regulated rate of return. In other regions, representing the focus of this paper—the second and third paradigms—the main segments of integrated utilities (generation, transmission, and distribution) are "unbundled." The transmission network typically remains regulated, while generation activities (and sometimes retail distribution activities) are opened to competition. Energy is then transacted in a wholesale power market. In the second paradigm, long-term adequacy is addressed through the energy market (so-called "energy-only" markets). In the third paradigm, there is an additional revenue mechanism to reward generators for their availability, regardless of actual generation (so-called "energy plus capacity" markets).

Policy debates in Europe currently focus on whether to transition to an energy plus capacity paradigm, since significant thermal generation risks becoming uneconomical in the next 20 years. In many rapidly developing economies, policy debates center on whether and how to move from a vertically-integrated paradigm to an energy-only or energy plus capacity paradigm in order to better meet rapidly growing demand, improve reliability, achieve better economic efficiency, and accelerate the integration of variable renewable energy.

This paper focuses on market designs that have emerged to meet these various challenges, and is structured along the three main domains of power markets—adequacy, energy, and ancillary services.

Adequacy: This function ensures adequate investment in capacity that is needed to meet future demand occurs with sufficient lead-time to complete construction and interconnection of the generating unit. High penetrations of variable renewable energy (with its inherently low marginal costs) have led to lower average prices in energy markets. Conventional generators—which will be displaced more often and sell energy at lower prices when they are selected—are likely to run at lower (and less predictable) capacity factors and earn less revenue from the energy markets (Milligan et al. 2012; Bauknecht et al. 2013), precipitating adequacy concerns. Also, the type of capacity (e.g., ability to cycle on and off) that the system requires in the long-term to ensure a reliable system becomes more important. Approaches to sustain adequate and appropriate capacity may include some combination of scarcity pricing, capacity markets, and capacity payments, and energy efficiency is increasingly considered an eligible resource in some markets.

Energy: This is the central transaction platform in power markets. To deliver energy when it is needed, generators are dispatched on an economic basis, subject to reliability constraints and congestion. In some markets, the economic dispatch of demand-side resources is growing significantly, altering the economics for conventional generators. Increased penetrations of variable renewable energy affect the energy markets in three primary ways: 1) the frequency and magnitude of changes to net load[1] increase, which in turn require that the system have capabilities such as fast ramping and frequent on-off cycling; 2) the possibility of forecast errors increases the difficulty in anticipating market outcomes, increasing the relevance of intraday markets (where available); and 3) the proportion of fully dispatchable supply could decrease as the low marginal costs of renewable energy displace them from the market.[2] Variable renewable resources, such as wind, can in many markets bid in as a dispatchable resource, but their performance improves significantly with good forecasts. Other energy market modifications reviewed in this report include: dispatch resolution, more frequent markets, ramp products, negative pricing, and forecast integration.

Ancillary services: This collection of services is necessary to maintain system balance between supply and demand, and to ensure voltage and frequency support. Many markets include secondary and tertiary reserves (e.g., regulation, spinning) in the ancillary services market; other services, such as system inertia and voltage control, are not subject to markets. Variable renewable energy can affect the design of ancillary services markets in the following ways. First, the variability and uncertainty of wind and solar energy increases requirements for various ancillary services, affecting the scheduling and pricing of those services. Second, their impacts vary depending on system conditions, which makes the ancillary service demands difficult to generalize across timescales and systems. Third, allowing variable renewable energy to participate in ancillary service markets can offer more supply to the market, but could offer challenges based on the unique characteristics of variable resources. The aggregate impact of significant variable renewable energy on the grid suggests the need for modifications to current ancillary service market designs and rules, and suggests the potential for new separate ancillary service markets.

Table ES-1 summarizes the market design considerations reviewed in this report.

Table ES-1. Market Design Considerations Reviewed for Adequacy, Energy, and Ancillary Services

	Adequacy	Energy	Ancillary Services
Market Design Considerations Reviewed	Scarcity pricing	Dispatch resolution	Dynamic reserve requirements (secondary and tertiary reserves)
	Capacity markets	More frequent markets	Primary frequency response
	Capabilities markets	Ramp products	System inertia
	Capacity provision by renewable resources	Negative pricing	Voltage control
		Forecast integration	Co-optimization
		Dispatchable variable renewables	Ancillary service provision by renewable resources

[1] Net load refers to electricity demand minus electricity supplied by variable renewable energy and hence the electricity that must be supplied by other resources.
[2] Hybrid systems (e.g., wind + storage, solar + storage, solar + natural gas) enhance dispatchability and thus revenue certainty to investors, but are not the focus of this markets report, which focuses market designs that accommodate variability and uncertainty.

Bridging Wholesale Markets and Emerging Technologies

Bridging opportunities between wholesale markets and emerging technologies, such as demand response, distributed generation, and distributed solar, has the potential to reduce system costs, including costs at the distribution level, where these resources in particular can address congestion, losses, and inadequate infrastructure. But, the distinct characteristics of these resources, particularly for distributed resources, present challenges to creating non-discriminatory access in the wholesale market. Examples of persistent challenges include:

1. *Increasing demand response participation.*
   Demand response holds significant promise to increase the elasticity and economic efficiency of wholesale market operation. Nonetheless significant barriers remain before these resources contribute in a significant way to system operation because traditional markets follow 20th century demarcations between wholesale and retail sides. Increasingly, market design might need to redraw these boundaries. Some markets, especially in the United States, have established new specifications that have clarified the role and trading parameters of demand response resources, resulting in significant participation.
2. *Integrating distributed generation.*
   Deployment of distributed generation, for example solar photovoltaic and combined heat and power, impacts wholesale market operation in unique ways. For example, in Denmark, combined heat and power plants are required to participate in wholesale power markets, and a third of the plants also participate in real-time energy markets. Distributed photovoltaic electricity, on the other hand, rarely participates in wholesale markets, but has an indirect effect by reducing net demand levels during midday hours that used to represent peak price hours. Given these unique characteristics, there will likely be no single approach to integrating distributed generation into market design. Instead, local contextual factors will figure prominently in market designs that result in coordinated deployment of centralized and distributed energy resources, as well as in the treatment of hybrid market actors such as microgrids.
3. *Clarifying the role of storage.*
   Electricity storage—mechanical, thermal, or chemical—promises to ease concerns over wind and solar market and system impacts and to decrease curtailment. Yet, significant policy and regulatory barriers make it difficult for storage to participate in centralized markets. For example, storage can provide generation, transmission, and distribution benefits, but in many markets storage can only be classified (and valued) as one type. Emerging solutions, such as allowing the owner of a storage resource to disaggregate these various services and sell them each to a third party for transaction in markets, could induce more optimal use of storage options.

Challenges to 21st Century Market Design

Wholesale market designs provide significant efficiency in real-time dispatch of system resources, and offer great promise for integrating variable renewable energy and introducing new resources on the demand side, because they help encourage innovation, minimize system costs, and facilitate access to a broad range of options that increase system flexibility. Yet, there remain ongoing challenges involved with the design of markets for enabling higher penetrations of variable renewable resources and emerging technologies. A few topics are listed below:

Minimizing Complexity: Around the world, most power markets have evolved into complex designs that integrate efficient economic principles with the engineering and physics of the electric power system. New designs, such as for flexibility, are being introduced, but at the cost of amplifying existing market complexity. Too much complexity could necessitate market revisions too frequently, fail to achieve extensive market participation, and create unintended conflicts between markets, such as energy market rules that create a disincentive to provide reliability services.

Encouraging Investment: In most wholesale markets, energy prices are based on the marginal cost of providing energy, and therefore do not include any of the capital costs of the resources. Investors calculate the risk adjusted returns of potential projects; and as energy prices decrease with increasing penetration of zero dispatch generation sources, other revenue sources become increasingly important, including scarcity pricing, capacity markets or payments, and bilateral, long-term power purchase agreements. There is debate as to the merit of each.

Harmonizing across timescales: A reliable and secure electricity supply requires sensitivity to multiple timescales. Electricity markets provide short-term price signals (seconds to days), which are effective at allocating available capacity. In contrast, few power markets provide any long term price visibility and are ineffective at incentivizing the optimal amount of long-term installed capacity to meet reliability (Cramton and Stoft 2006). A challenge in market design is how to provide long-term market signals to encourage investments in new merchant generation (renewable or otherwise).

Ensuring Market Depth: In many power markets, a significant amount of energy is sold through bilateral contracts, which addresses the absence of long-term market signals, but which reduces market participation. The implications for systems with high variable renewables but significant bilateral contracts are threefold. First, most energy delivery is purchased months to years in advance, locking in generation that could be inflexible, and leaving a small day-ahead and real-time market for new, innovative, and flexible supply. Second, spot-market prices might be inconsistent with marginal costs due to the limited supply of flexibility. Third, limited participation in the day-ahead and real-time markets can decrease market efficiency by reducing the potential for market software to optimize supply resources based on their bid costs.

Conclusions

Experience in many countries illustrates the value in using markets to access flexibility. Well-designed markets encourage economically efficient and stable solutions, promote desired behavior, and minimize unintended consequences. Yet, many uncertainties remain about how to evaluate system requirements and effectively induce and sustain investments in appropriate resources. This report reviews market designs that help access flexibility, and it suggests that sources of revenue could shift away from energy toward tailored services.

It is apparent that market design is a difficult task. Many competing objectives must be met, including using short-term price signals to incentivize long-term investments, minimizing market power, and providing incentives for suppliers for the many non-energy services that are needed to balance the grid. Wholesale markets in many locations are markedly uncorrelated with pricing mechanisms in the retail market. This means that participants in the wholesale markets have minimal ability to predict, plan, or account for consumer actions. Further, in some markets with scarcity pricing, spikes in wholesale prices serve only to increase total costs, and do not provide any incentives for consumers to change their behaviors to promote economic efficiency.

The challenge of appropriate market design becomes more apparent in emerging 21st century power systems. Assets such as variable renewable energy, demand response, storage, and distributed generation offer benefits that can be realized throughout the power system—generation, transmission, and distribution—and therefore are difficult to capture in current markets and regulatory structures, which deliberately segregated generation from transmission to support utility unbundling. The power system may require a transformation from a system premised on a strict separation between wholesale and retail, or generation and distribution, to one that can integrate these markets, such that assets from across the system can contribute to flexibility and reliability.

Moreover, market solutions are not the only option. Various hybrid designs—combinations of regulations and competitive markets—might serve as alternatives. A key driver in any market or hybrid design is to start with the characteristics that maximize the value of the power system and ensure that the type and quantity of services that deliver economically efficient operation and design of the power system are understood.

The power system is just that, a *system,* relegating various design and operational issues to entities that are uncoordinated, possess imperfect information, and possess varying degrees of market power. Moreover, these entities operate in a complex market with many economic externalities; thus economies of scope (e.g., coordination of transmission and generation planning) are difficult to achieve. On balance, however, markets can enable efficiency gains that emerge from competitive (or nearly competitive) markets in electricity. Nevertheless, market approaches remain just one option in a broader range of possible approaches, such as vertically integrated utilities.

There is an acute need for international collaboration on wholesale market design questions. A platform for collaborative analysis and modeling will help to evaluate pathways to 21st century power systems. Proposed market or hybrid market-regulation paradigms should be rigorously tested to understand both technical and financial outcomes, but also the alignment with the public policy objectives that drive market design. The 21st Century Power Partnership aims to provide this platform, and the authors of this report sincerely hope that it lays the groundwork for future collaboration.

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1 Introduction

Around the world, wholesale electricity market designs are being reconsidered in an effort to meet a broader range of objectives—including accelerating private investment, promoting competition and efficiency, encouraging the development and deployment of non–fossil fuel sources of energy, and increasing flexibility in system operation. In light of this growing interest in establishing or reforming wholesale electricity markets, there is a clear need for an international discussion of the market design principles and paradigms that can guide the transition to 21st century power system—a system which integrates variable renewable energy and emerging technologies such as smart grids, demand response, distributed generation, and distributed storage.

This report aims to identify and briefly discuss the landscape of key issues in wholesale market design for achieving power systems that are cleaner and more efficient, resilient, and reliable (*see* Text Box 1 for explanation of wholesale market terminology). It is the first in an ongoing series of issue papers from the 21st Century Power Partnership, a multilateral initiative to accelerate power system transformation. Contributors to this report include public- and private-sector experts from around the world, who provide a uniquely broad range of perspectives. Subsequent papers will examine international perspectives on related topics, such as emerging designs for the retail power market.

The report is structured as follows. Section 2 describes 21st century power systems. Section 3 examines specific market design features that have evolved to accommodate high penetration levels of variable renewable energy. Section 4 examines the need to bridge opportunities between wholesale market designs and emerging technologies such as demand response. Section 5 examines the likely challenges to effective market design. Section 6 explores a research agenda that might build international collaboration. Section 7 synthesizes conclusions.

Text Box 1. Wholesale Power Markets—Definitions

Wholesale power markets refer to the exchange of energy, ancillary services, and capacity in the bulk power system, which comprises the interconnected resources at the high-voltage level—generation, transmission, and interties to neighboring systems. The retail power market refers to the exchange of energy and services at the lower-voltage distribution level.

Bulk system (or "grid") operators go by different names in different jurisdictions. In Europe they are called transmission system operators (TSOs). In India they are called load dispatch centers. In the United States they are called regional transmission organizations (RTOs) or independent system operators (ISOs).

Approaches to system operation also vary widely. The United States, for example, uses two approaches to wholesale electricity market design—vertically integrated utilities and RTOs/ISOs.[3] The vertically integrated utility paradigm—common to many jurisdictions globally—relies on the public utility

[3] The U.S. RTOs/ISOs are California ISO (CAISO), Electric Reliability Council of Texas (ERCOT), ISO New England (ISO-NE), Midcontinent ISO (MISO), NYISO, PJM Interconnection (PJM), and Southwest Power Pool.

transmission provider to procure the necessary resources to manage the uncertainty and variability of the power system.[4] In the United States, the transmission providers are required to provide open access transmission service. In areas with RTOs/ISOs (the focus of this report), transmission owners gave operational control of transmission facilities to the RTO/ISO, which is an independent entity. The RTOs/ISOs allocate transmission rights based on a system of bids and offers, and optimize unit commitment and dispatch decisions to minimize system costs. In Europe, often the TSO both operates and owns the transmission facilities.

Operators of the low-voltage level, who reduce the voltage from the transmission lines and deliver power through distribution lines, also have different names, including distribution system operators (DSOs) in Europe and utilities in the United States. The load-serving entities (LSEs), such as utilities, competitive retailers, and the DSOs that sell electricity to retail consumers, purchase their power from the wholesale energy market. Many European DSOs are considered "entry gates" to retail markets and contribute to the effective functioning of energy wholesale markets (Council of European Energy Regulators 2013b).

This report uses "wholesale power markets" to refer to the unbundled, competitive markets, such as the RTOs/ISOs and electricity markets in Europe.

[4] Variability refers to variations in demand and supply, for example, wind and solar generation can vary based on changes in the intensity of their energy sources, and conventional generation and load can deviate from schedule. Uncertainty refers to unexpected events, for example, forced plant outages or load or wind forecast errors.

2 Toward 21st Century Power Systems

Globally, investment in power systems is expected to exceed $15 trillion over the next 20 years (IEA 2012), and electricity demand is expected to nearly double (*see* Figure 1). This growth will give added urgency to the goals of achieving affordability, energy security, reliability, and reduced health and environmental impact. In this context, energy-efficient devices, appliances, and power systems will allow for more rapid expansion of energy access. Renewable energy resources will support cleaner system operation, as wind and solar represent an increasing share of electricity generation.

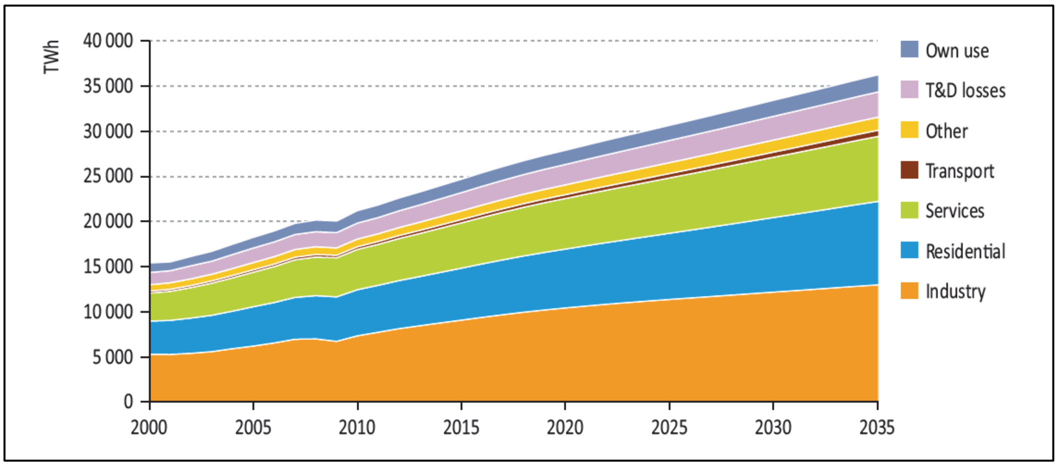

Figure 1. Projected electricity demand by sector, 2010–2035.
***World Energy Outlook 2011 © OECD/IEA 2011* (Fig. 5.1, p. 177)**

Expanding the grid penetration of solar energy and wind energy—and accommodating their variable output—requires more nimble power systems that can adjust quickly to balance supply and demand. At the same time, options for addressing the variability of solar and wind energy are being strengthened through advances in smart grids, communications, and technologies that enable dispatchable demand and distributed generation to extend to the mass market. Figure 2 illustrates the range of dynamic interactions that might characterize 21st century power systems.

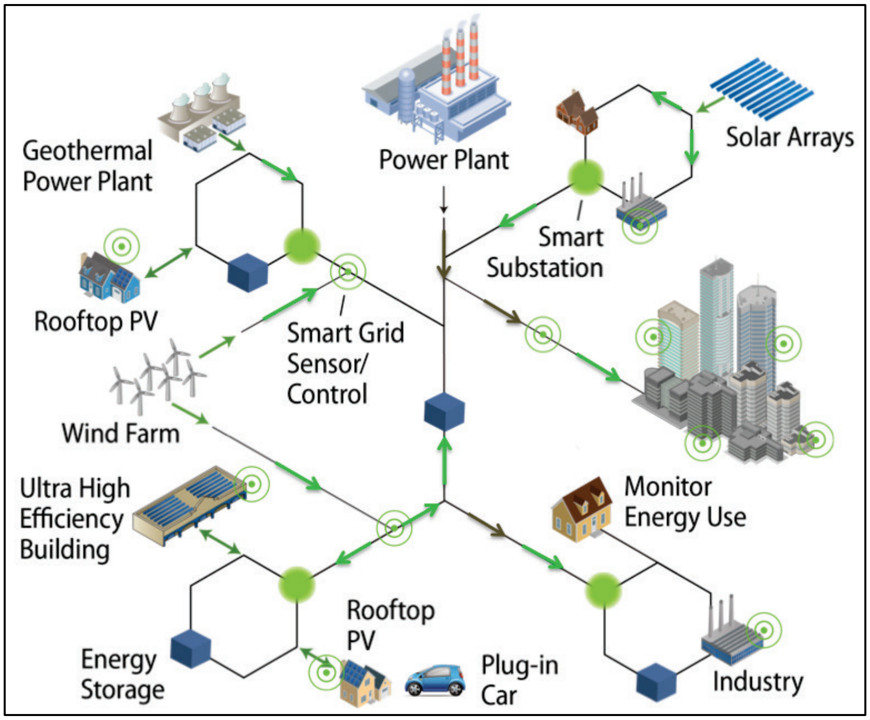

Figure 2. Illustrative view of 21st century power systems. *NREL*

Wholesale market design is crucial for realizing these opportunities, in two key distinct regards. In the operational sense, electricity market design defines the protocols for dispatching electricity in a reliable and economic fashion. At the same time, market design determines the long-term landscape of financial incentives and rules of eligibility for investment in resources that ensure a reliable and secure grid. The dual roles of electricity markets— simultaneously *operational* and *financial*—are a defining characteristic of electricity market design. Ensuring harmonization between the two roles is a persistent challenge. The need for harmonization is increasingly evident in the pursuit of 21st century power systems. For example, as a general trend, flexible performance (e.g., the ability to ramp quickly, as discussed in Section 3) and expanded resource eligibility (e.g., demand- , delivery- , and supply-side resources, as discussed in Section 4) are issues of growing importance, as new technologies and systems stand poised to enter both the wholesale and retail power markets.

There is a wide range of starting points and motivations for market development; therefore, the evolution of market design will follow myriad pathways. Some common objectives, however, are present in all systems, including:

1. Promoting efficient operation of power systems,
2. Creating clear and effective incentives for investment, and
3. Improving reliability and cost-effectiveness of electricity service.

These objectives have driven power market design for decades. More recently, other objectives have emerged that increasingly impact power market design, namely:

4. Reducing the health and environmental impacts of electricity service,
5. Rapidly expanding energy access to underserved or unserved customers, and
6. Encouraging power-system innovation.

The importance of the latter objectives depends heavily on context. Not all jurisdictions give equal weight to each of these objectives, and it remains to be seen what, if any, market designs optimize all of them. This report primarily focuses on the challenges and opportunities involved in achieving objective 4—a more energy-efficient and cleaner power system—but recognizes that objective 5 is a primary public-policy objective in many settings, which in turn influences the design of wholesale power markets and power system evolution generally. Policy makers and regulators working to create 21st century power systems must balance disparate or competing objectives, consult with broad networks of stakeholders, and attempt to render frameworks that advance the public good, recognizing that there exists no single solution that maximizes all objectives.

Wholesale power market design has evolved significantly since the first experiments in the early 1980s. Resolving fundamental issues of adequate investment, transparency, and competition, however, has proven to be a complex task. Further expanding the scope of market design to include objectives of health, environmental, energy access, and innovation presents new challenges and opportunities. For example,

- Promoting the entry of new sources of distributed generation could be perceived as a challenge to existing market participants (Lopes et al. 2007; Kind 2013);
- Rapidly expanding energy access might increase costs for other customers (Ranjit and Sullivan 2002; Brew-Hammond 2010); and
- Reducing health and environmental impacts by encouraging energy efficiency and greater deployment of variable renewable energy sources could challenge existing investment frameworks.

Although an examination of many of these interactions and tensions is beyond the scope of this report—which addresses specific market design concepts on the bulk power system, namely greater integration of variable renewable resources, energy efficiency, and smarter grids—the broader market design context is vital for understanding the drivers for policy and investments in energy at both the wholesale and retail levels (*see* Text Box 2).

This report focuses primarily on wholesale market designs and complementary operational practices administered at the system operator level. Retail market evolution also is important, however, and many forces in evidence today will prompt a reconsideration of the role of traditional utilities. Future research and analysis performed by the 21st Century Power Partnership will examine the parallel questions concerning the transformation of the power sector on the retail side, including how utilities can earn a return on services in a context of increasing energy efficiency, significant demand response, and distributed generation.

Text Box 2. Electricity Markets in the Context of Power System Reform

Power system reform processes have been revealed to be sensitive to contextual factors—technical, financial, political, and institutional—that constrain options and pathways for the design of electricity markets. Broadly speaking, power system reform efforts globally fall into three categories. The first consists of mature, restructured markets in which significant generation capacity already exists, and where economic, social, and technological forces are precipitating a reassessment of market design. Most markets in the European Union (EU), Australia, and the United States fall into this category, with a reassessment driven by slow demand growth, rapid growth in energy efficiency and variable renewable energy, and increased interest in deploying smart-grid technologies.

The second category consists of "hybrid markets" (Gratwick and Eberhard 2008), in which earlier restructuring efforts have stalled out, leaving a mix of competitive and state-owned actors. Many emerging economies fall into this category, including Tanzania, Argentina, Bolivia, Jamaica, and various states within China and India. In many of these settings, the impetus for continued market reform stems from rapid demand growth, lagging investment in new capacity by independent power producers, and poor financial conditions of state-owned entities. In contrast with earlier rounds of restructuring, many of these countries also show growing interest in adding variable renewable energy to the generation portfolio and investing in smarter distribution grids—new objectives that significantly change the market reform conversation.

The third category consists of monopoly power sectors, in which little or no restructuring has occurred. Mexico and South Africa fall into this camp, for example. Similar to the second category, in these settings the impetus for power system reform typically is driven by a need for accelerated private investment to meet rapidly growing demand or the need to change the current inefficient set-up of pricing and dispatching.

The set of electricity market design principles that has been developed and refined largely in developed economies faces translational challenges in emerging-economy settings. These challenges stem both from the different objectives of emerging economies—especially meeting rapidly growing demand and improving energy access—but also due to unique institutional challenges that commonly occur in developing countries. Four unique institutional challenges have been identified that are relevant to the translation of market-design principles: Limited regulatory capacity, limited accountability, limited commitment, and limited fiscal efficiency (Estache and Wren-Lewis 2009).

Limited regulatory capacity pertains to the ability of regulators to implement and enforce policy. Limited accountability refers to the level of accountability to which regulatory institutions are held. Limited commitment refers to the diminished ability to rely upon contracts (Guasch et al. 2003).[5] Limited fiscal efficiency refers to the difficulties in financing infrastructure investment. The prevalence of four challenges varies significantly by jurisdiction, but all are important considerations in the development of electricity markets.

Although addressing the full diversity of institutional challenges and power system contexts is beyond the scope of this report, it does attempt to provide general insights into the unique challenges that emerging economies could face in the transition to market frameworks.

[5] *See*, e.g., Guasch et al. (2003). The authors discuss the common occurrence of renegotiated government concessions, and estimate that in Latin America between 1985 and 2000, more than 40% of concessions (excluding the telecoms sector) were renegotiated—the majority at the request of governments.

3 Wholesale Market Design Principles for Integrating Variable Renewable Energy

This section reviews wholesale market designs in use and under consideration to ensure adequacy and security in a landscape of significant amount of variable renewable energy. The concepts are organized along three categories of markets commonly found in mature contexts: Capacity adequacy, energy, and ancillary services.[6] These three categories represent the foundational market domains of the bulk power system that will enable 21st century power systems. Table 1 provides an overview of the design considerations reviewed in this section.

Table 1. Market Design Considerations Reviewed for Adequacy, Energy, and Ancillary Services

	Adequacy	Energy	Ancillary Services
Market Design Considerations Reviewed	Scarcity pricing	Dispatch resolution	Dynamic reserve requirements (secondary and tertiary reserves)
	Capacity markets	More frequent markets	Primary frequency response
	Capabilities markets	Ramp products	System inertia
	Capacity provision by renewable resources	Negative pricing	Voltage control
		Forecast integration	Co-optimization
		Dispatchable variable renewables	Ancillary service provision by renewable resources

3.1 Adequacy

Ensuring resource adequacy is a critical function of power system policy and market design. In jurisdictions with wholesale energy markets, the central challenge of this issue is balancing the power generators' desire to minimize investment risk with the public-policy priority to maintain cost-efficient and dynamic functioning of wholesale power markets.

Broadly speaking, ensuring minimal investment risk for generators (for example through long-term contracts) shifts risk to consumers. Conversely, ensuring cost-efficient market function (for example, forcing all generators to compete in economic dispatch with no guaranteed production) shifts the risk to generators. Well-functioning wholesale markets do not guarantee long-term

[6] Another important component of electricity market design, the financial transmission rights market, is not extensively covered herein. Although these auctions could change based on the changing flows and changing locational marginal prices from high penetrations of variable renewable resources, the fundamental design of the market remains relatively unchanged from greater adoption of renewables in the electricity market, and therefore these markets were omitted from this report.

Also not considered in this report are costs and benefits of renewable energy systems on the grid, such as energy loss savings or costs, increases or offsets of transmission equipment, and environmental benefits, and policy and market designs that would create incentives specific to new renewable energy generation. This report instead focuses on market designs to accommodate existing variable renewable energy and emerging technologies, and market modifications needed to ensure adequacy of supply from all sources. For more on international best practices to achieve new renewable energy generation, *see* Miller et al. (2013).

revenue certainty, therefore price and volume risk over the long term imply that less-efficient generators might—and perhaps should—go out of business.

The policy and regulatory challenge in designing markets, therefore, is to fairly apportion risk while meeting social, economic, and environmental objectives. In pursuit of economic operation of power systems with large proportions of variable renewable energy, market design increasingly aims to avoid rewarding inefficient generators, and instead encourages efficient, flexible units. Even in well-developed and integrated markets, such as in the European Union and in one of the most integrated markets—the Nordic Nord Pool region—this design challenge has proven to be significant.

Additional challenges include the lead-time needed to develop new generation resources and the often even longer lead-times needed if new transmission services are required. Although this period can be relatively short for renewable resources such as wind or solar energy, it can take up to several years for natural gas combined-cycle power plants—and even longer for coal-fired or nuclear plants—and take as much as a decade or more for new green-field transmission services. Some additional mechanism therefore might be needed to ensure investment in the long-term security of supply in a timely manner, so that enough generation with the desired attributes is available when needed.

To evaluate whether a current or projected power system meets adequacy requirements, wholesale markets and regulators primarily use one of two metrics. Either a fixed percentage of peak load (e.g., 15% planning reserve margin above peak load), or a probabilistic measure—the loss of load probability (LOLP)—is used. As new generation is added to the resource mix the LOLP generally declines. The effective load-carrying capability (ELCC) metric then is calculated to determine the contribution that any given resource makes to the reliability target. This often is an LOLP of 1 day/10 years (Keane et al. 2011a). The North American Electric Reliability Corporation (NERC) makes a similar recommendation (NERC 2011).

How markets then achieve adequacy reflects an ongoing debate about whether a reserve requirement is necessary and who should bear the risk. Some markets and regulators, such as Nord Pool, rely on energy-only markets through scarcity pricing, to ensure sufficient cost recovery for generators and thus maintain sufficient planning reserve margins. Generators bear the market risk of meeting annual income targets through the power market. An alternative approach is to require the RTO/ISO/TSO or load-serving entity to maintain a target planning reserve margin, which could be satisfied through a centralized market mechanism (e.g., RTO-based capacity market or payment), or decentralized requirements (e.g., require an LSE to demonstrate sufficient reserve margins for its specific distribution system, such as through long-term, bilateral contracts). In this context, the ratepayer bears the market risk of paying for too much capacity. Bilateral power purchase agreements—a predominant mechanism used by CAISO)—make it possible that these requirements could limit participation in energy-balancing markets, and thus would limit flexibility. Following an overview of these two mechanisms—scarcity pricing and capacity markets—the impact of variable renewable energy on these market options is discussed.

3.1.1 Energy-only Markets with Scarcity Pricing

Scarcity pricing[7] implies that when demand is very high, the supply may be insufficient and/or costly to deploy to meet the load (Stoft 2002, p. 70). These price spikes reflect the relative inelasticity of supply (and demand) at high load levels or due to other sources of capacity constraints. Scarcity pricing can be designed to encourage investments in flexible response, such as storage and price-responsive load, because these resources can respond quickly to brief periods of scarcity. Scarcity pricing is favored in some markets on the basis that policy interference in pricing mechanisms, such as through a capacity market, would jeopardize market participants' trust in the market and discourage investors from investing in new capacity.

In practice, regulators in many energy-only markets impose bid caps in an effort to protect consumers from too high and volatile prices and to mitigate market power. Also, some energy regulators are tasked to procure strategic reserves to ensure long-term adequacy. Strategic reserves are withheld from the market entirely or included only when prices are high—they create a de facto price cap for the market (European Commission 2012b). In Finland, for example, where the power system is part of energy-only Nord Pool Spot, capacity adequacy is the responsibility of the Energy Market Authority. Capacity can be acquired from new peak load plants, demand response, or old units (based on bids), which would otherwise be dismantled and instead receive "power reserve" payments. In the latest auction, demand response was able to participate to deliver part of this reserve. The need for the reserve was calculated with ELCC calculations considering wind power and stochastic imports from neighboring countries. Without neighbors, Finland would have a capacity deficiency.

Scarcity pricing predominantly is found in the European Union, where the policy goal in several states has been to combine scarcity pricing with carbon prices to increase the competitiveness of low-carbon flexible units and use extensive interconnections to balance integrated regions. Nevertheless, the European Union reflects different policy approaches to adequacy, and member state policy actions have yet to create a coordinated market-based approach. The differing approaches to adequacy have complicated cross-border trades, such as those between countries with and without capacity payments (European Commission 2012b).

Examples of energy-only markets with scarcity pricing: Australia's NEM, Nord Pool, ERCOT

3.1.2 Reserve Requirements: Capacity Markets or Payments

Alternatively, or even to supplement scarcity pricing, a capacity market or some form of capacity payment could help ensure revenue adequacy. Although the specific characteristics among existing capacity markets differ, their common objective is to procure capacity for a future time period—often 1 to 3 years. A qualifying resource that participates in the capacity market receives a payment in return for providing capacity in the day-ahead market, or some other requirement. Capacity markets also have their own challenges, including the potential abuse of market power and providing sufficient incentives to induce the desired level of capacity in forward markets. The ISO-NE Capacity Market, for example, conducted five years worth of auctions that did not

[7] Scarcity rent is revenue minus variable operating cost, which is needed to cover startup and fixed costs (Stoft 2002). Scarcity pricing reflects the situation in which generators are supplying at full output, and load would be willing to pay a generator more than its variable cost of production to produce more.

clear at a competitively set auction price, and instead cleared at an administratively set floor price (Coutu 2011).

In the United States, where capacity markets are more common, the markets offer 1-year contracts, auctioned 3 years in advance of delivery (ISO-NE and PJM) and 6-month contracts, 1 month in advance (NYISO).[8] Yet, these markets have not been critical to initiating new investments (Caplan 2012), and they have been challenging to design due to difficulty in anticipating required levels and types of capacity (Milligan et al. 2012). Also, the timescale of current markets (6 months to 1 year) does not match the timescale needed to secure financing and attract new investments (e.g., 15 years minimum). In comparison, most power purchase agreements range in duration from 20 to 25 years. Furthermore, existing capacity markets do not differentiate between resources that have different flexibility attributes. This likely will become more important as the shares of variable renewables and demand response in the electricity supply increase.

A new variant on reserve requirements that is gaining support in the European Union is the use of a reliability option contract (Keay et al. 2013), which is the financial version of capacity markets (Bauknecht et al. 2013). This mechanism imposes a reserve obligation on the buyer of electricity (e.g., retail company, system operator). Capacity is sold via an auction, which establishes a strike price in the day-ahead market. Sellers then must provide capacity at the strike price when called upon (i.e., when market prices are high). Generators must pay the difference between the spot price and the strike price. This addresses concerns of market power during scarcity, because generators are encouraged to make capacity available at high prices. Because they must pay the difference between the spot market price and the strike price, generators do not gain from price manipulation (Bauknecht et al. 2013).

In Europe, the question of capacity remuneration mechanisms is discussed very differently among the member states. Conventional power plants (even new flexible gas plants) are being closed or are threatening to close not only because some are at the end of their lifetimes, but in some cases because of changes in fuel prices. As a result, generation adequacy regionally is becoming a matter of concern (European Commission 2012b; Council of European Energy Regulators 2013a; Miller et al. 2013). Also, limited interconnection capacity, for example in countries such as Spain, has increased interest in capacity payments (*see* Text Box 3).

In Europe, security of supply is a national question, but over-capacities would occur if solved strictly nationally. Thus, European organizations and associations strongly recommend international coordination (European Commission 2012a; European Wind Energy Association 2012; ACER 2013; ENSO-E 2013).

Examples of energy markets with capacity mechanisms: Ireland, Spain, Ontario, PJM, NYISO, and ISO-NE

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[8] Other design differences include auction style (descending clock vs. sealed bid), participation (for example, the PJM capacity market is open to transmission upgrades; ISO-NE and PJM's timeframe allows new resources to participate), and measurements of availability (such as whether a generator is penalized for a forced outage during tight capacity periods) (Coutu 2011).

Text Box 3. Revisions to Spain's Capacity Mechanisms

In 2012, capacity payments represented 10.2% of the total Spanish market price (Red Eléctrica de España 2012). Recently, a new competitive capacity mechanism has been proposed (Ministerio de Industria Energía y Turismo 2013), which includes an investment incentive for a 10-year period and is conducted through an auction configuration. The incentive amount is calculated as the product of the capacity value of the technology (for example, 0.95 for nuclear and 0.09 for onshore wind power) and the result of the auction. The incentive includes a hibernation mechanism, which would allow the possibility of temporarily closing generation units when capacity is exceeded, especially during minimal load periods. The plants scheduled for hibernation also are determined through an auction. Additionally, availability service is applied for 1-year periods and combined cycle and coal thermal plants are able to participate. Hourly payments for this service are calculated as a function of a monthly payment, hourly total thermal generation, and hourly total dispatchable thermal generation.

There is no widespread agreement on the need for a capacity mechanism to supplement energy-only markets—and, if the need exists, how best to do it. There also is little, if any, evidence regarding whether scarcity pricing would result in revenue sufficiency for capacity, as illustrated by the current review of options in ERCOT (Newell et al. 2012). Because most retail consumers do not see real-time prices that reflect cost, the demand curve for electricity is muted (Stoft 2002; Kirschen and Strbac 2004). Proponents for capacity mechanisms argue that this malfunction of the market for electricity, coupled with the lack of ability to differentiate reliability among customers on a widespread basis, renders an energy-only market incapable of providing sufficient forward capacity (Cramton and Stoft 2006). This debate is not new, and began long before variable renewable energy sources were significant in the electricity supply.

Text Box 4 describes Brazil's approach—using capacity auctions to achieve adequacy through long-term contracts. Text Box 5 discusses how capacity markets can be designed to invite participation by demand-side resources (demand response).

Text Box 4. Brazil: Market-based Mechanisms to Meet Reserve Requirements

In Brazil, the power system is dominated by hydro generation. Capacity adequacy assumed urgent importance in 2001, as years of successive droughts resulted in reservoir depletion and widespread power rationing. Subsequent reforms implemented from 2004 onward have established long-term contracting of power as the only form of electricity procurement (Pinguelli Rosa et al. 2013). This principle has been driven by the urge to reduce investment risk for new capacity additions. By this metric, the reforms largely have been successful, resulting in significant investment in new capacity.

The 2004 reforms established two separate energy-trading environments. In the first, the Regulated Contracting Environment, energy is sold by electric utilities, independent power producers, self-generators, and power marketers; the only buyers are distribution companies that are required to contract their entire forecast demand for captive consumers. Contracts are auctioned off over time with delivery dates of 1, 3, and 5 years after the date of the auction. There are separate auctions for "new" and "existing" electricity.

Within this environment, contracts for new electricity are longer (duration of more than 15 years) than those for existing electricity (duration of 8 years). Distribution companies are required to contract

100% of their expected power needs, but there are annual "adjustment" auctions where they can buy additional energy when their forecasts are inaccurate. In the regulated environment, "marketers"—entities that either may purchase and resell energy, or may only help broker deals between buyers and sellers—are only allowed to participate in these adjustment auctions.

The second trading environment is called the Free Contracting Environment, and brings together electric utilities, independent power producers, self-generators, marketers, importers, exporters, and free consumers (those that do not need to buy power from distribution companies, typically industrial and commercial firms). Buyers and sellers are free to enter bilateral contracts and negotiate prices, quantities, delivery dates, and conditions. The Free Contracting Environment, also known as the "free market" in Brazilian electricity sector parlance, has been growing steadily in the past few years. It consisted of about 1,650 free and special consumers in 2012, which accounted for approximately 27% of total consumption in the Brazilian electricity system (ABRACEEL 2012).

Dispatch decisions essentially are made on a hydro-centric schedule of weekly increments, part of the legacy of a hydro-dominated system. Slow dispatch periods significantly limit short-term system flexibility. Similarly, the pure long-term contracting environment in Brazil could blunt economic signals—for example prices of natural gas—that could lead to generator fuel switching in the medium-term. Taken together these characteristics of the Brazilian case illustrate that a focus on procuring resource adequacy, and operational rules focused on large legacy generators, could conflict with other market objectives such as short-term and medium-term flexibility.

Text Box 5. Bidding Demand Response into U.S. Capacity Markets

In some U.S. capacity markets, demand response can bid in alongside new generation resources. This serves a dual role in power system evolution, on the one hand shaving peak load and mitigating the need for new supply-side resources, and on the other hand providing a supplemental revenue stream for load beyond the avoided energy costs. Such allowances of capacity markets appear to stimulate investment. For example, in the PJM capacity market in the eastern United States (known as the "reliability pricing model"), the megawatts of demand response resources that bid into the auction for delivery in year 2015/16 grew more than 150% over the amount bid into the prior year auction (EMC Development Company 2012), representing 9.6% of total cleared capacity (Bowring 2013). Currently, some of the PJM products allow limitations on demand response's availability (e.g., number of events per year). To make the quality of demand response participation equal to thermal generation, demand response could be required to meet the same performance obligations, i.e., no limits on number of events, for example by bundling multiple demand sites that can be aggregated to provide unlimited interruptions (Bowring 2013).

It should be noted however that stringent measurement and validation of demand response is required for market participation, and demand response does not resolve all issues related to flexibility, system stability, or incentives for retaining some amount of thermal generation. Demand response is discussed more extensively in Section 4.

3.1.3 Variable Renewable Energy—Impact on Adequacy

With high penetrations of variable renewable energy from wind and solar, the expectation is that the inherently low marginal costs of these generators will lower average wholesale energy prices (*see* Figure 3). Conventional generators, which will be displaced more often and sell energy at lower prices when they are selected, are therefore likely to run at lower (and less predictable) capacity factors and earn less revenue from the energy markets (Milligan et al. 2012; Bauknecht et al. 2013). In these markets, energy prices might be zero for extended periods of time, and generators risk receiving average energy revenues that fall short of their average costs (Stoft 2002). In markets with capacity payments, capacity prices will increase as net revenue from energy markets decreases. In energy-only markets, if scarcity pricing is insufficient, then generators might need supplementary sources of revenue for their continued provision of services that enable the power system to maintain sufficient reliability (Bowring 2013).

Furthermore, the type of capacity that the system requires in the long-term to ensure a reliable system becomes more important. Although generation planning has typically been about the energy (e.g., peak MW) capacity—and capacity alone—that new resources would add to the system, future planning could require system participants to offer certain traits or capabilities, such as flexibility. In doing so, incentives must be in place to ensure that new capacity brings with it these traits. The following new market designs represent approaches to address these topics.

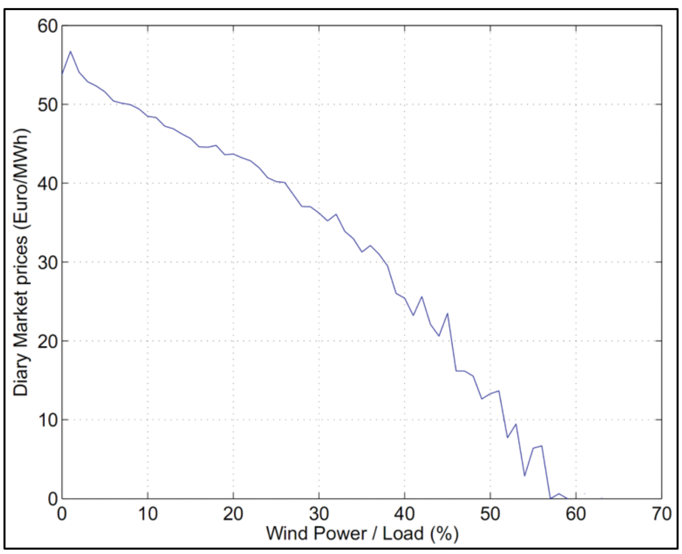

Figure 3. Mean diary [daily] market prices based on wind penetration levels (Spanish hourly data, 2007–2012, provided by Red Eléctrica de España)

3.1.4 Capabilities Markets

Understanding that undifferentiated capacity markets, even over long time horizons, would be insufficient to create investment incentives for the right types of resources, the Regulatory Assistance Project (RAP) has proposed a capabilities market that addresses the quality of the capacity (Hogan 2012). RAP suggests two approaches. For markets without capacity markets, it proposes an enhanced services market mechanism, which would create periodic forward auctions to procure the required mix of balancing capabilities from new and existing generators. For markets with existing capacity markets, RAP suggests restructuring them to apportion the requested capacity over tranches of varying quality. RAP cites PJM's early version of its 2006 market design as an example of possible tranche types: Dispatchable ("rampable"), flexible cycling (fast and frequent stopping and starting), supplemental reserves, and all others. This approach necessitates prioritizing the type of capacity needs and establishing appropriate metrics. The value in having a differentiated capacity mechanism depends in part on whether energy and ancillary services markets alone create sufficient incentives for flexibility (e.g., through ramping products; discussed in Section 3.2).

3.1.5 Capacity Provision by Renewable Resources

Variable renewable energy resources such as wind and solar power can contribute to resource adequacy, but typically do so at a lesser fraction of their installed capacity as compared to conventional resources such as coal or gas. Biomass and geothermal can contribute to long-term planning close to their rated capacity as long as there are no significant fuel-supply constraints (long-term fuel adequacy for biomass, heat constraints for geothermal). The capacity contribution of wind power ranges from about 5% to 40% of rated capacity (Holttinen et al. 2013).[9] The wide range is a result of differing levels of correlation between wind energy delivery and load level. The capacity value of a variable resource starts to decline at greater penetrations, when the events with low variable generation start to dominate the peaks in the net load. Work on solar energy is emerging.

Other approaches are under development for differentiating the value among generation options. For example, Text Box 6 describes the approach that Mexico is taking to include environmental externalities in merit order dispatch as a way to stimulate new investment in renewable capacity.

Text Box 6. Mexico: Incorporating Environmental Externalities in Electricity Dispatch[10]

Incorporating the value of environmental or social externalities into power generation is one of the key challenges of a 21st century power system—reducing the health and environmental impacts of electricity service while maintaining the traditional motivation of improving reliability and cost-effectiveness of electricity service. The Mexican Power and Climate Change legal framework mandates the federal government and the national utility, Comisión Federal de Electricidad (CFE), to incorporate the value of environmental and social externalities into the pricing of electricity.

Until recently this mandate was performed by CFE, the Secretariat of Energy, and the Secretariat of Public Finance as part of a cost-benefit analysis of selected renewable energy projects, and not included in the initial stages of sector planning when technologies are evaluated against each other on a cost basis. This limited the transformative impact on sector planning. Since 2012, the federal government began revising the framework for a new externalities policy, with a protocol that includes not only the cost-benefit analysis from CFE, but which also incorporates externalities into merit-order dispatch and planning for new investments by CFE. The Transversal Strategy for Productivity 2013–2018, published on August 30, 2013, mandates "Establishing prices and tariffs of energy that incorporate environmental externalities and promote its efficient use," which addresses the need to provide market-based

[9] The low end of the range reflects situations where, for example, wind generation occurs primarily during non-peak hours, but is also affected by other factors such as total installed wind capacity.

[10] This text box was contributed to the report by José María Valenzuela of the Secreteriat of Energy in Mexico.

mechanisms for achieving such goals, and which includes private investors.

Some of the main challenges to implementing the protocol and other policies that value externalities include the need for significant investment in research infrastructure and human resources, as well as coordination among environment, health, and energy sectors. But even if externalities are properly valued, there is the need to choose adequate implementation mechanisms to enable transformative consequences.

Renewable energies—both conventional and unconventional—are included in dispatch entirely due to their low marginal generation costs. Hence, developing an externalities policy for dispatch only modifies the merit order among fossil-fuel generation, providing a competitive edge for natural gas versus heavy fuel oil, on the short term. Yet, the system capability to increase power generation from gas is limited by gas supply infrastructure. Therefore, commitment to an externalities policy fosters new, cleaner investments if public and private investors receive adequate pricing signals on future developments. While CFE is mandated to include the value of externalities in the levelized generation cost for its technologies, private actors are not required to make such a commitment.

Carbon pricing directly or indirectly through a tax on fossil fuels would provide such a price indication for global pollutants. Nevertheless, schemes for pollutants of local and regional impact shall remain in place to complement the externalities policy system, leaving the incorporation of externalities into the dispatching merit tables as the more certain tool.

3.2 Energy

Wholesale energy markets comprise the central transaction platform in power markets. Although some details in energy markets can vary, as discussed below, in all cases energy markets attempt to arrive at an economic allocation of generator dispatch that meets demand and satisfies security constraints.

In the United States, the energy markets run by RTOs/ISOs consist of two-settlement markets, where electricity is procured in a day-ahead market, followed by a real-time market, which meets any imbalances that occur. The locational marginal price (LMP) is the price paid to generators, and is set by the marginal cost to serve load in a particular location. If congestion restricts sending lowest-cost electricity to a particular location, higher-priced electricity is dispatched and the higher price is reflected in the LMP. Generators have financial schedules in the day-ahead market that are paid the day-ahead LMP, and any additional generation they are asked to provide in real time is paid the real-time LMP. If they reduce output relative to schedule, generators pay back that portion of the amount committed day-ahead at the real-time LMP. Most of today's U.S. energy markets are co-optimized with ancillary services markets, and incorporate transmission constraints into the price setting. Generators and loads have the option to settle outside the market, through bilateral contracts. The congestion costs that occur between them, however, must still be paid through contracts for differences. LMPs allow a close alignment between market schedules and real-time dispatch.

Most European markets offer day-ahead and intraday markets. In Europe, the power systems and energy markets are operated separately; the market clears a dispatch order, which then can be adjusted to accommodate transmission constraints. Germany, for example, with its extensive bilateral market contracts, requires longer gate closures to allow the TSO to conduct load-flow calculations and coordinate with neighboring TSOs, which in turn requires significant re-dispatch to resolve transmission constraints (Miller et al. 2013).[11] Nord Pool offers zonal pricing.

Increased penetrations of variable renewable energy affect the energy markets in three primary ways.

1. The frequency and magnitude of changes to net load increase, which in turn require that the system have capabilities such as fast ramping and frequent on-off cycling.
2. The possibility of forecast errors increases the difficulty in anticipating market outcomes, increasing the relevance of intraday markets (where available).
3. The proportion of fully dispatchable supply could decrease as the low marginal costs of renewable energy displace them from the market.

Although wind turbines can serve as a fast ramping, flexible, dispatchable resource, wind energy and other variable resources, such as solar photovoltaics, have less predictability and availability than conventional energy supplies.[12] The following market mechanisms are examples that could improve the ability of markets to accommodate these changes and better value flexibility.

3.2.1 Dispatch Resolution

Energy markets that consist of short-dispatch intervals (e.g., 5-minute dispatch intervals), which already have been adopted in many restructured markets, improve system flexibility by more closely matching the changes in variable generation and load ("net load") economically. As net load changes, the dispatch optimization responds as well—cost-effectively optimizing generation. Short-dispatch interval markets also reduce the required levels of regulating reserves needed, which are the automatic resources that can respond to minute-to-minute fluctuations and are the most expensive ancillary service (Smith et al. 2010). High energy prices during the ramp periods also could provide an incentive for flexible supply. All generation receives the energy market clearing price in an energy market, as opposed to markets with ramp products, described below.

3.2.2 More Frequent Markets

A two-step market with unit commitment in the day-ahead timescale will leave significant forecast errors to be resolved during real-time balancing. The balancing resources acting on the timescale of a few minutes can be relatively expensive (Kirby 2007). An alternative is to have some form of intraday market that enables participation from power plants with intermediate lead/start-up times (Kiviluoma et al. 2012).

For example, the Iberian market already has a considerable share of variable generation. The market structure consists of a day-ahead market followed by six sessions in the intraday market.

[11] Gate closure refers to the future time at which the market commits to deliver electricity. Typically, gate closures that occur close to the actual delivery time (e.g., 5 or 15 minutes in advance) can help minimize the magnitude of forecast errors and associated reserves and allow for trading at potentially lower costs than power that would otherwise be required to balance day-ahead schedules (Cochran et al. 2012).

[12] Wind generation can serve as a dispatchable resource by operating at reduced outputs, such as in response to a dispatch to ramp down, or in anticipation of a dispatch to ramp up. For example, MISO offers a Dispatchable Intermittent Resource Program, which allows wind to bid into energy markets.

The gate closure in the intraday market is 3 hours and 15 minutes. The intraday market is at times followed by a deviation management market, which is used when a deviation of more than 300 MWh is expected to last several hours. A tertiary regulation market is used to recover secondary regulation reserves in the intra-hour timescale.

In the Nord Pool Spot, there is a day-ahead market followed by an intraday market, which matches bids continuously until one hour before the hour of delivery. This decreases liquidity in comparison to the Iberian intraday market, which has sessions that concentrate the trades. The Iberian intraday market, however, has a longer delay between the trade and delivery. Consequently, in Nord Pool there is no need for a market between the intraday and tertiary regulation market, which is called the regulating power market in Nord Pool (and the real-time market in the two-step markets). Nord Pool's regulating power market requires activation in 15 minutes and also is used to meet operating reserves.

3.2.3 Ramp Products

Ramp products, akin to proposals for flexible ramping and ramp capability products in the CAISO and MISO markets, respectively, are designed to periodically complement the fast energy market by providing for operational flexibility to meet load more reliably and efficiently, as well as incentivizing the specific resources that provide the flexibility to do so. The ramp product market price can have supplemental payments that are provided only to those resources providing the ramping support. Ramp products therefore reward only the flexible generation and, during these flexibility-scarce periods, do not reward inflexible resources. The ramp capability price would be zero during most hours, when ramping capacity in the energy dispatch mix is sufficient to follow load (Ela et al. 2012a). When ramping is needed—whether due to expected variability, or uncertainty in meeting the net load in future intervals—and not provided by the energy market, the price would reflect the marginal cost of providing that ramping capability, incentivizing flexible resources.

To add ramp capability and ensure sufficiently fast response, the Spanish TSO in May 2012 implemented a new market for the management of additional upwards reserves (Ministerio de Industria Energía y Turismo 2012). EirGrid, the TSO in Ireland, also has proposed a new ramping product to respond to imbalances that occur over the minutes-to-hours timeframe, such as from changes in demand, wind generation, and interconnector flows. The TSO anticipates a broad range of resources to supply this service, including wind and photovoltaic (PV) plants that have been dispatched down, conventional generators, storage, and demand (EirGrid and SONI 2012).

3.2.4 Negative Pricing

Negative pricing can occur when serving the next increment of demand would actually save the system money; that is, the marginal cost to serve load is negative. For example, negative pricing can occur due to a lack of flexibility within the system. This might be due to limited transmission capacity creating location-specific negative pricing, minimum generation periods during which resources (e.g., coal, nuclear, hydro) cannot be shut down, and other reasons. Negative prices also can occur during periods of high variable renewable energy generation and low loads. In general, this can happen either due to resources setting the price with negative cost offers (e.g., due to production credits), or because of reduced capability to reduce generation and increase load (e.g., due to self-scheduled resources). Incorporating negative pricing into market design facilitates balancing and provides a financial incentive to increase system flexibility for several reasons.

- Negative pricing can discourage generators, such as wind (unless tax incentives encourage production), nuclear, and coal from providing too much power when demand is low.
- Negative pricing sends a strong signal to generators to be more flexible and reduce constraints on flexibility. In Denmark, the minimum running capacity of some older coal-fired power plants has been reduced from 30% to 10% of maximum capacity due to dynamic and negative pricing (Blum 2013).
- Negative pricing can encourage greater diversification in the location and types of variable renewable energy, especially in transmission-constrained areas.
- Negative pricing can encourage the use of storage to absorb excess production, and load to increase demand.
- Negative pricing can provide a transparent mechanism for curtailment of renewable resources via market means rather than out-of-market procedures.

One concern about negative pricing in the United States is that with the production tax credit—which in 2013 offers wind generators a $0.023 subsidy for each kilowatt-hour of energy produced—wind energy can still generate revenue when prices have become negative. They then can offer negative prices representing this "effective" cost of generating. This subsidized bidding can distort the clearing price and impact the rest of the generation fleet. A second concern with negative pricing is that it makes revenue streams more difficult to calculate, and therefore can deter investors from participating in energy markets.

When implementing negative prices, it is important for markets to coordinate with neighbors with respect to the use of administratively defined minimum price levels. At present these minimum price levels differ, for example, between Germany and Denmark, where flows from Germany to Denmark have been observed when Danish prices were negative and extra power was not needed, but German prices were even more negative. For example, this occurred in December 2012, when Danish bids were curtailed to achieve market equilibrium above the minimum price level, but even cheaper German power was imported anyway. Currently, measures are under consideration to avoid this occurrence in future. As already occurs in Denmark, individually negotiated compensation for offshore plants could be designed to eliminate fixed feed-in compensation during hours of negative prices to relieve stress on the power system, and this could be extended to include compensation from all wind power production.

3.2.5 Forecast Integration

All U.S. RTOs/ISOs, all European TSOs with significant wind (e.g., Germany, Denmark, Spain, Portugal, Sweden), and most provincial dispatch centers in China forecast wind power production. The use of these forecasts, however, varies considerably from region to region (Porter and Rogers 2009). TSOs in Germany are mandated to trade wind power in day-ahead (and intraday) markets (where feed-in tariff support mechanisms apply). In other countries (e.g., Finland, Sweden, Norway), market participants must make their own forecasts for the portfolio they are bidding. In the United States, most RTOs/ISOs use a centralized day-ahead wind power forecast in the reliability unit commitment model, but not in the day-ahead market unit commitment model. This ensures that the RTO/ISO will have enough capacity to meet the forecasted demand with consideration of the forecasted wind power, but might not necessarily mean that it will be done in the most efficient manner. Power production forecasts are also used to improve situational awareness.

Integrating advanced, centralized forecasts into market operations could increase market efficiency and provide additional opportunities for wind and solar resources to participate in electricity markets. A challenge in many countries is how to set up the most efficient forecasting model—a mechanism to dynamically improve forecasting using both central and project based forecasting could be the way forward. Text Box 7 describes forecasting advancements in China.

Text Box 7. Forecasting Advancements in China

In China, the State Grid's Jibei Electricity Power Company Limited has been using a new energy forecasting tool from IBM in phase I of its 670 MW solar-wind energy facility. As a response to utility requirements, IBM created the Hybrid Renewable Energy Forecasting (HYREF) solution that performs advanced data analysis to improve predictions of wind turbine output. Using multiple data sources, including wind turbine sensors, weather forecasts, and images of clouds, the software can forecast power output for as brief a period as 15 minutes and as much as a month in advance. The combined weather and demand forecasting system has increased wind integration by 10%, powering 14,000 additional homes.

As important as the technology solution demonstrated in China is for renewables, it was the change in system operation rules and market design that provided the catalyst. Over the last decade, the massive deployment of wind in China has stressed the transmission and distribution system at key areas, increasing curtailment and other non-optimal outcomes. In 2011, China's energy ministry and regulator issued a new forecasting requirement imposed on all renewable energy projects interconnecting to China's grid. It is now law for every interconnecting wind, solar, and other utility-scale renewable project to provide day-ahead weather and energy forecast to the operator. This critical operations and policy change spurred the development of the 670-MW demonstration project by increasing market demand for more accurate and higher resolution forecasting capabilities for renewable energy plants. This issue of policy creating market demand for private-sector investment is not trivial. For example, the misalignment between actual renewables output and system demand stretches from up to 4 hours daily for wind and to up to 1.25 hours daily for solar. Matching renewable supply to demand could be worth up to $733 million globally (Dehamna 2013).

3.2.6 Allowing Variable Renewable Energy to Participate as Dispatchable Generation

Wholesale power markets historically have treated variable renewable energy generation similarly to nonresponsive load in its dispatch optimization—a price taker with zero price elasticity (Ela and Edelson 2012). This worked with low penetrations, when market operators wanted to maximize the amount of this low, marginal cost generation. Increasing penetrations of wind and greater instances of negative energy prices mean that a more efficient solution is to allow wind generation to make schedule and price offers (usually zero, reflecting marginal production costs) into the market akin to other generators, based on their most recent forecast. Similarly, enabling the operator to order the wind plant to ramp down temporarily to relieve congestion can allow plant dispatch to be optimized at the system level, can increase overall reliability and efficiency, and can ensure that curtailments are not conducted manually (Ela and Edelson 2012). In Europe, wind can—and in some cases must—bid into day-ahead markets and some intraday markets (closing one hour before delivery), but is not included in real-time markets. Many of the U.S. RTOs/ISOs now allow wind plants to submit offers for energy in the day-ahead markets. The New York ISO was the first to permit bids from wind plants, followed by PJM and MISO. In 2010, MISO introduced its "dispatchable intermittent resources" program, which allows wind plants to bid into the real-time market and update those bids based on sub-hourly forecasts.

The inclusion of renewable energy in markets affects revenue risks and project economics (e.g., from curtailments and imbalance charges) (Miller et al. 2013). In markets such as MISO, some contracts between wind generators and off-takers have required revision to reflect changes to the formal classifications of curtailments causes, which in some cases has shifted from reliability to economic. Although evaluating such rules in terms of project economics is beyond the scope of this report, markets can be designed to shift the responsibility for flexibility from specific plants to the system, such as through measures described above (e.g., intraday markets, short gate closure, better forecasting) (Bauknecht et al. 2013).

3.3 Ancillary Services

Grid reliability under conditions of significant instantaneous (e.g., 20% or greater[13]) renewable energy penetrations remains a particular concern of system operators. Although numerous studies have shown the impacts of integrating these renewables at the levels realized to date to be modest (GE Energy 2008; CAISO 2010a; EnerNex Corporation 2010; GE Energy 2010; Danish Energy Agency 2013), there are still outstanding questions on the best ways to integrate them reliably and efficiently, and also how to do so at greater levels of penetration.

Ancillary services, as defined by the Federal Energy Regulatory Commission (FERC) and NERC, are those services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission service provider's transmission system in accordance with good utility practice. Ancillary service markets typically include spinning, non-spinning, and regulation reserves (Hirst and Kirby 1997). Other ancillary services, such as voltage control, reactive power, and black start are serviced through cost-based mechanisms and do not have markets (Rebours et al. 2007). The ancillary service markets are simultaneously cleared with the energy market in the two-settlement system. Prices are uniformly cleared based on the marginal value of that service. The price could include an availability cost as well as a lost opportunity cost. The lost opportunity cost is the revenue that a resource can forego in a separate market in order to provide capacity for that ancillary service. Ancillary services also have administratively set scarcity pricing, where the price reflects a shortage of the particular service. Some ancillary services also have location constraints, but they typically are not as strict as transmission constraints in the energy markets.

[13] The threshold for "significant" is system-dependent, and can be much greater in some jurisdictions before penetration levels become a concern.

Variable renewable energy can affect the design of ancillary services markets in three key ways.

1. The variability and uncertainty of wind and solar energy increases requirements for various ancillary services, affecting the scheduling and pricing of those services.[14]
2. Their impacts vary depending on system conditions, which makes the ancillary service demands difficult to generalize across timescales and systems.
3. Allowing variable renewable energy to participate in ancillary service markets can offer more supply to the market, but could offer challenges based on the unique characteristics of the variable resources in question.

The aggregate impact of significant variable renewable energy on the grid suggests the need for modifications to current ancillary service market designs and rules, and the potential for new separate ancillary service markets. Some of these possibilities are reviewed below.

3.3.1 Dynamic Reserve Requirements (Secondary and Tertiary Reserves)[15]

Some of the recent renewable integration studies (EnerNex Corporation 2010) analyzed the effect that variable renewable resources would have on operating reserve requirements (*see also* Text Box 8). The most recent studies have all concluded that the requirements should not be static, but in fact should change based on the actual and predicted conditions of the system (Ela et al. 2012a). The quantity of required reserves is proposed to vary hourly—which is not typically found in current operating-reserve requirements. Allowing reserves to vary by time of day and system conditions can better target the high-risk periods of significant change in the wind resource and reduce integration costs (Smith et al. 2010). By having a requirement that changes each hour based on predicted conditions, market participants would have to plan ahead to understand what the ancillary services demand might be, similarly to how they anticipate the load demand (Ela et al. 2012a), which again makes it more relevant to have a market for these services.

One method of implementing a time-varying system reserve requirement is to have a reliable forecast of every unit, in near real time and crossing both balancing authorities and multi-utility system operating boundaries. Although RTOs/ISOs have some level of this capability now and receive forecast data, real-time visibility and access to, for example, meter-level data for aggregate demand-side forecasts, is extremely rare on a global basis. Generally speaking, the distribution-level power system does not exhibit sufficient sensing, monitoring, and real-time computational power to provide the level of reliability that operators expect from conventionally powered units. As demonstrated in the forecasting example in the previous section, mandatory rules—such as a requirement that changes each hour based on predicted conditions—can be a powerful change agent and accelerate development of the technological solution to the

[14] Contingency reserves, based on the size of the largest generator, remain constant if the renewable generator is not the largest plant.

[15] Nomenclature for reserves varies widely (Rebours et al. 2007). In this report, primary reserves refer to the automated droop response of governors. Secondary reserves refer to synchronized resources that can respond rapidly to automatic control signals from the system operator to move up or down. Tertiary reserves refer to the resources that respond to non-automated dispatch commands that respond to planned and unplanned events, such as forecasting errors and outages.

operational problem. In other words, the technologies for "smarter energy" systems can meet the challenges put forth by greater renewable energy integration. What is required is a balance between three (sometimes competing) policy and regulatory objectives in the wholesale power markets worldwide, namely: (1) a non-negotiable reliability requirement, (2) dynamic and negotiable energy policies, and (3) a non-dynamic and deliberately paced regulatory rule-making methodology.

Text Box 8. Impacts of Wind on Reserve Requirements: Experience of Spain

Balancing services in Spain are primary reserves, secondary reserves, tertiary reserves, and imbalances management. Primary reserves are not influenced by wind-power penetration, and non-dispatchable generation is planned to contribute to this reserve. The use of secondary reserves is affected slightly by wind-power ramping, but the required level of reserves remains unchanged. Tertiary reserves are influenced by wind power variability when wind power ramps are opposite to load ramps but, even so, the required level of reserves has only marginally been increased due to wind. Conversely, the use of and the required levels of imbalances management have experienced a significant increase due to wind power uncertainty. These reserves are offered in day-ahead markets as a function of wind power forecast error, guaranteeing balancing reserves from day-ahead to real time.

Text Box 9 describes the market-based approach used in India to maintain grid frequency.

Text Box 9. Indian Mechanisms for Grid Discipline—the Unscheduled Interchange

Since 1994, frequency discipline in India has been managed through the "unscheduled interchange" mechanism. The unscheduled interchange specifies a price curve linked to frequency, such that participants in the power system (both generators and load-serving entities such as utilities) face financial incentives to maintain grid frequency. Generators that deviate from their scheduled supply, for example, could either benefit or be penalized depending on whether the deviation is in the direction necessary to maintain grid frequency. So if the grid is operating above 50 Hz, and the generator under-supplies relative to its schedule, it incurs no penalty; rather it saves on fuel cost. If the grid is operating below 50 Hz and the generator delivers less power than scheduled, it pays a penalty linked to the deviation and the frequency rate at the time. Thus, there is a strong financial incentive to reduce generation (or increase demand) during high-frequency times, and to increase generation (or decrease demand) during low-frequency times (Bhusan 2005).

3.3.2 Primary Frequency Response

Although secondary reserves (also called regulation and secondary frequency control) help control frequency by maintaining balance, more immediate frequency control is accomplished by governors in the immediate seconds following a disturbance. This autonomous response is what stabilizes the frequency and helps avoid the triggering of under-frequency and over-frequency relays or instability that could lead to machine damage, load-shedding, and—in the extreme case—blackouts. Because conventional generators provide this service as part of interconnection, and because there was, at least in the large synchronous interconnections of the continental United States, more than enough frequency response in supply, this service was not explicitly compensated through cost-based measures or market designs (Ela et al. 2012a).

The move to organized energy markets might have made the provision of frequency response a disincentive, however. This is because its provision could reduce plant revenue by requiring plant operation at somewhat less than maximum output to provide capacity to support frequency response, and because generators can be penalized for schedule deviations that might be needed to provide frequency response (Ela et al. 2012b). Several modifications could provide positive incentives for frequency response, including adding frequency response characteristics to other ancillary services markets, adding this service as a requirement for interconnection, or adding a new separate market product holding its own specific characteristics and schedules and prices (Ela et al. 2012a). Once the need for frequency response is recognized and made an incentive, emerging technologies which might not inherently have these capabilities will have the motivation to create innovative ways of attaining them (Miller et al. 2011).

3.3.3 System Inertia

Variable renewable energy lacks inherent inertial response, which helps the system remain stable in the initial moments after a disturbance, before the automatic response by governors. Simulations by the Western Electricity Coordinating Council have shown that frequency response degrades during periods of high wind and low load, when conventional generators comprise a small share of the dispatch mix (Ela et al. 2012a).[16] The simulations also show that it is technically possible for wind to sufficiently emulate this inertial response by connecting to a power electronic converter; some load and storage also can supply similar capability. Inertia is an inherent part of synchronous generation, therefore it has no added cost other than being online, and so a market similar to the other ancillary service markets, with changing schedules and prices, might not be the best approach. If some resources do provide the service, and others do not, however, then some sort of compensation might be required.

3.3.4 Voltage Control

Reactive power, which supports voltage control, does not travel far due to high inductive impedances. It therefore is very localized which, in turn, inhibits a broad competitive market. Challenges for reactive power markets are further compounded by rules governing the procurement and use of reactive power capabilities. In general, all generators except wind plants are required to be capable of providing reactive power within a power factor range defined in their interconnection agreement, although in Spain new operating procedures are being studied to require wind turbines to provide voltage control (Ministerio de Industria Energía y Turismo draft). Compensation for provision of this service varies by transmission provider. In the United States, there is no requirement to compensate generators for reactive power within the power factor range unless the transmission provider is compensating its own generators. Generators typically are paid for fixed costs as well as opportunity costs; that is, any costs it foregoes in the energy markets because of constraints on providing reactive power (Federal Energy Regulatory Commission 2005). Yet, market simulations demonstrate potential for a competitive reactive power market. For example, simulations assert that in an optimal market, nodal reactive power prices would remain at zero, except during contingencies, when prices would be low (Thomas et al. 2006). This pricing scenario still would meet long-term average costs due to the low cost of investment in reactive power supply. The complexities of solving the market models with a

[16] The Western Electricity Coordinating Council is a regional forum that promotes electric service reliability in western Canada and the western United States.

reactive power provision—which would require solving the full alternating current power flow problem at intervals of as little as 5 minutes[17]—remains impractical, even though there can be significant benefits from a reactive power market (Hogan 1993; Cain et al. 2012).

3.3.5 Co-optimization

The co-optimization of energy and ancillary services has improved the market efficiency of scheduling and dispatch (Hirst and Kirby 1997; Singh and Papalexopoulos 1999). Nevertheless, exceptions to co-optimization might be necessary to ensure a broad base of supply for ancillary services. Load is ill-suited to co-optimization, for example, because the opportunity cost for participation includes factors beyond energy price, and participation particularly depends on the duration of response (Ela et al. 2012a). Storage, with its limited energy, also is not suitable for co-optimization. NYISO changed its market rules to exempt storage from co-optimization in the energy market (Smith et al. 2010).

3.3.6 Ancillary Service Provision by Renewable Resources

Although much research has focused on how variable renewable resources could increase the need for ancillary services, variable renewable resources also can be used to provide these ancillary services (Miller and Clark 2010; Miller et al. 2011; Ruttledge and Flynn 2011). Currently, rules do not allow this provision in most of the ancillary services markets. In Germany, auctions for frequency control reserves occur six days in advance, which effectively precludes wind energy from bidding due to forecasting uncertainties (Holttinen et al. 2012). Variable generation, however, can provide great flexibility. Variable renewable generators can have fast electronically controlled ramp rates, zero minimum generation levels, and no start-up time needs. With increased penetrations, it might be more economical to utilize variable renewable resources to provide these services for both consumers (in terms of reduced production costs) and for variable renewable generators (in terms of increased profits) (Kirby et al. 2010). Text Box 10 describes the provision of ancillary services in some markets by demand response.

[17] Today's real-time markets typically use a DC power flow, which ignores reactive power and variations in voltage.

Text Box 10. Provision of Ancillary Services by Demand-side Resources

Demand-side resources increasingly are providing ancillary services to the grid, in roles that require faster and more verifiable performance than traditional uses of energy efficiency. Demand-side resources long have been employed in ways that only require several hours of lead time, such as "interruptible load" for emergency peak shaving (Pfeifenberger and Hajos 2011) or to increase nighttime load during off-peak price periods. Yet, provision of ancillary services occurs on much shorter timescales, typically seconds to minutes. Such fast-acting demand response is employed in several U.S. wholesale markets including ERCOT, PJM, and MISO (Pfeifenberger and Hajos 2011).

System security requires that such systems ensure rigorous performance characteristics (response time and minimum load size), special contractual and compensation mechanisms, robust measurement and verification methodology, and high-speed communications interface to enable automatic control. As such, industrial sources have predominated in providing ancillary services. Pilot and demonstration projects are underway to aggregate residential and commercial resources to provide ancillary services (Navigant 2012), but significant legal and technical barriers remain to ensure adequate performance characteristics.

4 Bridging Opportunities Between Wholesale Markets and Emerging Technologies

Bridging opportunities between wholesale markets and emerging technologies—such as demand response, distributed generation, and distributed storage—has the potential to reduce system costs, including costs at the distribution level, where these resources can address congestion, losses, and inadequate infrastructure (Sioshansi et al. 2012). The distinct characteristics of these resources, however, particularly distributed resources, present challenges to creating non-discriminatory access in the wholesale market. This section reviews wholesale market considerations specific to each of these types of resources.

4.1 Demand Response

Increasing the price responsiveness of electricity demand, either through voluntary reaction to price signals or through contractual commitments to change demand in response to system events, holds promise for reducing system peaks and adding significant flexibility to the grid. The technical potential for demand response is growing. Globally, some analysts estimate that 55% of all meters globally will be "smart" by 2020 (Navigant 2012). This widespread deployment of smart meters enables residential and commercial demand response to be more widely integrated in power markets, but various technical obstacles remain. For example, the reliability with which demand response can directly cushion the variability of renewable energy depends on its characteristics. From a flexibility perspective, prized qualities include: direct dispatchability to either increase or decrease demand; little or no advance notification; fast response; ability to be called upon frequently; and verifiable visibility to the operator (Cappers et al. 2012; Cutter et al. 2012).

Beyond the technical obstacles, institutional barriers also inhibit demand response—in the residential sector in particular—from fully participating in wholesale markets. Two critical institutional barriers are regulatory and customer-related barriers, but some market rules also represent barriers in many locations.

4.1.1 Regulatory Barriers

Current regulatory structures are the greatest barriers to increasing the potential for demand response (Kirby et al. 2011). These structures typically reflect the traditional demarcation between wholesale power markets and retail rates and programs, and often are ill-suited to demand response, which straddles the wholesale-retail divide. In the United States, for example, RTOs and ISOs under the regulation of the Federal Energy Regulatory Commission operate wholesale power markets and maintain reliability, and they can design energy and ancillary markets to include demand response. The extent to which RTOs/ISOs can integrate demand response is limited, however. Retail rates are the jurisdiction of the states, and RTOs/ISOs are not structured to interact with small customers or to determine demand baselines.

In most settings, regulated utilities (i.e., load-serving entities, distribution system operators) directly serving customers are the main intermediary for retail rates and customer interaction. This means that retail customers are not legally allowed to "cut out the middle-man," participating directly in wholesale power markets and gaining direct exposure to variability in reliability and price. Instead, LSEs, with regulatory approval, serve the function of creating price and event signals and interacting with retail customers, but their institutional options also are limited. Many LSEs, for example, have programs that curtail individual loads to reduce peak demand. If aggregated, such individual load control also could potentially be sold in the wholesale market as an ancillary service product, although at the time of this writing such an arrangement has not been demonstrated at full scale. The LSE could face various local regulatory restrictions, however; for example, on the number of times it can curtail load, thus eliminating the option of frequent but short-duration spinning reserves. In the PJM Interconnection in the United States, where the RTO/ISO coordinates demand response, some LSEs view PJM as a competitor in aggregation services (Greening 2010).

Another source of customer-related complexity that varies across different regulatory environments is the legal treatment of third-party aggregators on the customer-side of the meter. Third-party aggregators—in locales where they are allowed to operate—can develop demand-response programs without prior approval and restrictions by regulators, although the ability of these aggregators to set prices and demand response-event thresholds and frequency might be unclear, thereby limiting investment.

This disjointed regulatory structure gives rise to a situation in which federal regulators can require system operators to implement demand-response programs that impose costs on local utilities, but these utilities must seek approval from local regulators to recover costs from customers (Greening 2010). These persistent disconnects between distribution and transmission systems pose a variety of challenges to the integration of distributed resources and raise issues such as data sharing and systems control. These and other broader concerns are becoming increasingly important for grid planning and operations.

In many ways, the regulatory obstacles to demand response revive the conversation about retail electricity market reform—a process that has been less widespread than wholesale market reform.[18] The question is whether residential demand response could emerge more quickly in a competitive retail market arrangement than in fully integrated monopoly arrangement. In Denmark, a national smart-grid strategy seeks to finalize the rollout of retail smart meters by 2015, in time for a new model of variable (hourly) pricing schemes at the retail level, connected to the planned wholesale accounting system (Danish Ministry of Climate, Energy, and Buildings, 2013). In the European Union, four different task forces on smart grids recently have been working to clarify appropriate market models (Eurelectric 2013). Regulatory reforms that have been suggested include recalibrating the roles of RTOs/ISOs, LSEs, and third-party aggregators based on their roles in providing information. For example, RTOs/ISOs could provide a market platform, with information on price elasticity associated with bids; LSEs and aggregators could provide market research and information to customers on risks and benefits (Greening 2010). Also proposed is the unbundling of utility services—restricting utilities and LSEs to incentive programs and price and event signals (the utility side of the meter)—and allowing other market providers to offer services on the customer side of the meter (Cappers et al. 2012). This type of structure is in use in Finland, where demand response aggregators are market participants and DSOs only are allowed to provide indiscriminate aggregator access to the smart meters.

[18] Retail electricity market reform will be discussed in greater detail in a future 21st Century Power Partnership report.

Over the next several years, these important regulatory questions could be translated into action in countries that have plans to launch comprehensive energy-market reform, for example Japan, India, and Mexico. Generally speaking, all three countries are starting from scratch in the wholesale energy and capacity markets, as well as in the definition of—and demand-side participation in—retail markets. After a long period of vertically integrated, monopolistic market design, the Japanese power sector is moving towards both unbundling and retail competition (Ministry of Economy Trade and Industry 2013). The new energy reforms recently approved by the Japanese Cabinet primarily focus on unbundling the generation, transmission, and retail sectors by breaking the DSO's into private-sector actors, with a second phase planned to spur retail competition.

Similarly, India is considering pathways to increase the fiscal health and efficiency of retail DSOs, while simultaneously seeking to integrate increasing amounts of wind energy, and reduce the widespread incidence of involuntary load-shedding. Leaders in the Indian power sector seek a more market-based approach to load management, based on voluntary response to dynamic tariffs (ISGAN 2013a). Smart meters, which will support this dynamic tariff scheme, still are in early stages of deployment, but there are plans to dramatically increase deployment. Enacting operational rules that clarify the interaction between retail demand response, wholesale energy, and ancillary services markets could be important in the emerging Indian regulatory framework.

In Mexico, smart-meter deployment has been piloted in various communities by the national utility, CFE, as a means to increase reliability and to reduce operating costs and non-technical losses (ISGAN 2013b). The president of Mexico recently proposed broad restructuring of the power sector, with a near-term focus at the wholesale level. At the same time, significant new wind generation is expected in Mexico. Looking forward, some of the flexibility necessary to integrate this wind might be accessible from demand response at the retail level, providing that the regulatory framework is made clear.

4.1.2 Customer-related Barriers

A second major barrier to incorporating demand response is customer willingness and ability to participate in ways that provide clear system benefits. In most cases, this means allowing equipment to be dispatched automatically, either by the system operator or a third-party "aggregator" participating in wholesale markets. To best serve as a resource for grid integration and respond to year-round variability and uncertainty, dispatchable equipment should be available all year (e.g., water heaters as opposed to air conditioners), and at a range of timescales (Cappers et al. 2012).

Communications standards are needed to enable secure load control, accurate metering, and a platform for transacting data with individual customers. Nevertheless, some customers have expressed concern about smart meters and outside control of appliances, and regulators are navigating the questions about who should pay the extra costs of automation equipment and the marketing of demand-response programs. Additionally, in many settings retail customers also hold long-standing expectations of flat electricity prices.

Several proposals have been made to reduce these barriers, including rate-based recovery of infrastructure investment, marketing efforts that illustrate potential savings under dynamic rate structures, incentives and rebates for smart appliances, and the encouragement of third-party aggregators, particularly if utility services are unbundled (Greening 2010; Cappers et al. 2012). Designing an appropriate mix of these measures requires attention to promoting customer participation within specific technology, market, and regulatory scenarios (Greening 2010).

Some European projects investigate both technological and social acceptance issues, such as the Ecogrid.eu project (2011–2014), in which 2,000 private customers located on the island of Bornholm, Denmark—which is supplied by 50% renewables—can participate in the real-time market. The participants' houses are being equipped with devices that use remote control and intelligent control to promote flexible demand. The customers can see the real-time prices and set their individual automatic flexible demand. Experience with different types of smart metering and social acceptance is being gathered in this project.

Similarly, in the United States, a series of consumer-behavior study projects initiated in 2010 aim to investigate the impact of both technology and pricing variables on smart-grid deployments. The studies investigate the demand impact of various technology packages—smart meters plus a range of in-home informational devices—together with variable pricing plans, such as prices pegged to real-time wholesale prices versus tiered prices linked to critical peak hours (Department of Energy 2011).

Across jurisdictions there is an emerging view that, regardless of individual consumer behavior, it is important to create the right market structures to allow third-party aggregators to innovate new products and arrangements to control a large number of load devices, such as water heaters, heat pumps, or electrical vehicles. The city of Kalundborg, Denmark, for example, has provided an open platform and incubator program for companies to test business models for controlling electricity, water, heating, transport, and buildings (Smart City Kalundborg 2013).

4.1.3 Market Rules

Power markets evolved to accommodate conventional dispatchable generators. This makes it challenging to incorporate retail demand response, where participation is mediated by factors that include retail rate structures and limitations on duration and frequency. Changes to tariffs and reliability rules might better value demand response.

Real-time pricing offers a direct avenue for mass-market participation in demand response markets by allowing customers to experience the variability in pricing and adjust their demand accordingly (Hogan 2010; Cappers et al. 2012). This would obviate the need for most demand-response programs and the associated difficulties in designing market rules to allow their participation. Real-time and other scarcity pricing also could help demand response to mitigate market power by offering a means for moderating supply shortfalls and controlling price excursions. Price risks could be mitigated by allowing demand to participate in forward markets (Greening 2010). Although real-time pricing could be structured as an optional alternative to regulated tariffs, this option nevertheless would require the support of state regulators, who historically have worked to insulate customers from variability.

Barring this approach, market rules would have to be designed specifically to include demand response in the bulk power system. Hogan (2010) described the difficulties in valuing demand response in energy markets as the difference between reselling something you have purchased, and selling something that you would have purchased, without actually purchasing it. One complication is establishing a baseline methodology, and this methodology can differ among forecasting, impact estimation, and billing (Cutter et al. 2012). Direct dispatch, however, or the option to dispatch via capacity payments, simplifies these calculations (Cutter et al. 2012). In FERC Order No. 745, the Commission described a net benefits test to identify the cost-effectiveness of using demand response to balance supply and demand. This rule requires RTOs/ISOs to pay demand response at the LMP rate when the net benefits test shows that a demand-response resource is cost-effective.

In Finland, part of the zonal Nord Pool spot market, sufficient electricity to cover demand is bought on the day-ahead market and the transaction is financially binding. In this market, demand response can be built into the bid with price and volume steps. At later markets, demand response will be offered as a deviation from the original schedule. At real time, any remaining deviation in the balance of the LSE is addressed using the regulating power market, which has a 15-minute activation time. Demand response also can participate in that market.

Participation in ancillary markets might be more straightforward when automated demand response is relatively indistinguishable from generation, and new market rules are better at valuing the speed and accuracy of demand response, which usually is faster than the typical 5- to 10-minute services (Kirby et al. 2011).[19] Nevertheless, changing utility business models and requirements of demand-response resources regarding, for example, attributes of performance and revenue availability, are some of the most effective ways to reduce barriers to participation in ancillary services markets (Cappers et al. 2013).

Other proposed changes include separating regulation up from regulation down to be inclusive of loads that provide only unidirectional services (Cappers et al. 2012). Market-clearing software could better incorporate the participation of demand response by including individual operating constraints, such as duration, frequency, and notification times (Kirby et al. 2011). Forecasting to reflect uncertainty also would improve operations and long-term planning (Kirby et al. 2011). There also are concerns that prices for ancillary services could fall below sustainable levels with significant participation by demand response, which can have zero opportunity costs (Kirby et al. 2011). Co-optimization with the much larger energy markets however, so far has limited the impact of new resources on prices (Cappers et al. 2013). In the Nordic power system, a large portion of the primary frequency reserve is served by industrial loads. The opportunity cost can be high, however, as this method often leads to short interruptions in the industrial processes.

4.2 Distributed Generation

Distributed generation, which is generation located within distribution networks or on the customer side of the network (Ackermann et al. 2001), can help decrease transmission and distribution losses, and offset the need to upgrade infrastructure. In particular, microgrids—which can dispatch and manage local generation and demand—have the infrastructure to interact with the wholesale power markets. Some types of distributed generation, such as combined heat and power, can readily participate in wholesale power markets. Other types, such as residential

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[19] *See*, for example, PJM's new (October 2012) performance score to calculate compensation for regulation services, "Enhanced Certification, Measurement, Differentiation." This service provides greater compensation for faster response.

PV, only will interact with the bulk power system as penetrations increase. Distributed generation's potential negative impacts on the grid include voltage increases, power fluctuations, and unintentional islanding.

Combined heat and power plants primarily use fossil fuels to produce both electricity and low-temperature steam for district heating. In Denmark, these plants are required to participate in wholesale power markets, and a third of the plants also participate in real-time energy markets.[20] Their electricity generation therefore is optimized by the power markets—when competitively priced, combined heat and power produces electricity and its heat byproduct. When Denmark's significant wind generation reduces prices, combined heat and power plants cease electricity production and rely on thermal storage to maintain heating (Kiviluoma and Meibom 2010). The thermal storage enables combined heat and power to complement wind power rather than compete with it.

Residential PV currently remains primarily of interest at the distribution level. In the United States, states regulate residential PV through the LSEs and residential tariffs, and there is little interaction with the bulk power system. Residential PV in many jurisdictions is valued according to the retail rate its power offsets; therefore, it is valued higher than it would be through wholesale markets. As PV prices continue to fall, penetration likely will increase significantly. Structuring the wholesale power market to accommodate this generation without curtailment would create a disincentive for centralized ("curtailable") PV. Increased penetrations also likely will lead to revisions in interconnection standards to require PV to provide reliability services—such as reactive power support—mirroring the evolution in standards and expectations of wind generation as its penetration increased. Germany already has instituted low-voltage ride-through standards for grid-connected PV, even at the residential level (Passey et al. 2011).

Economic signals and system operator controls on the distribution grid that are similar to wholesale power markets collectively could help integrate wholesale and retail markets (Sotkiewicz and Vignolo 2006). Currently, there are no pricing mechanisms on the distribution grid due to the complexity involved. Having transparency on the distribution grid via prices would both create economic opportunities for distributed energy resources and improve bulk-power operations on systems with variable renewable energy (Rahimi and Ipakchi 2012).

4.3 Storage

Storage is an asset that can act as a generator, load, or alternative to transmission, and it can provide significant flexibility for the bulk power system. Except for storage that can be centrally dispatched, such as compressed air energy storage and pumped hydro, storage faces some of the same barriers to participation in wholesale markets as demand response, including incomplete valuation (e.g., by reducing costs of plant cycling), restricted access to markets (e.g., behind-the-meter storage), and conflicting regulatory structures as described below (Sioshansi et al. 2012).

Although some market products discussed above would be well suited for storage (e.g., ramping, voltage support), other characteristics of storage still would be inadequately valued. For example, distributed storage can alleviate distribution-related congestion, but LMPs reflect only

[20] In Denmark, real-time energy markets are called "regulating power markets."

transmission congestion. Also, the energy in behind-the-meter storage (typical of customer-owned thermal energy storage) cannot be dispatched and is limited to utility rates, which lack scarcity and variable pricing that could improve its economics.

Regulatory structures also pose considerable challenges for complete valuation of storage (Sioshansi et al. 2012). Storage can provide generation, transmission, and distribution benefits, but in the United States it can only be classified as one type. Generation is valued in wholesale power markets, whereas transmission and distribution assets are rate-based. The FERC has not allowed rate-based transmission and distribution assets to participate in energy markets, and a full market-based approach would inadequately value the transmission and distribution services of storage. Both choices result in suboptimal use of storage. One way to get past this barrier is to disaggregate the services by allowing the storage owner to sell storage capacity to a third party (Sioshansi et al. 2012).

5 Challenges to 21st Century Market Design

Market frameworks offer great promise for achieving 21st century power systems, insofar as they encourage innovation, minimize system costs, and facilitate access to a broad range of options that increase system flexibility. Yet, there still are ongoing challenges involved with the design of markets for enabling greater penetrations of variable renewable resources and other emerging technologies. A few of these challenges are listed below.

5.1 Minimizing Complexity

Electricity markets have evolved into complex designs with the goal of integrating efficient economic principles with the engineering and physics of the electric power system.[21] Complex market designs might be critical in helping achieve desired outcomes, but such designs also could make it difficult to attract extensive market participation.[22]

In some cases, design elements introduced to meet emerging objectives, such as for flexibility, can amplify existing market complexity and cause undesired interactions with existing market designs. Flexible resources have numerous attributes including, for example, the ability to start and ramp quickly, cycle on and off, and absorb excess power. To achieve flexibility, market designs seek to value these multiple attributes at multiple timescales. Although the aim of electricity market designs is to be indifferent to resource type, this becomes difficult and complex when resources have different characteristics that are not easily compared in the market. Flexibility can be provided by generation, demand response, transmission, and storage resources, each with differing capabilities. The difficulty of rendering markets simple enough to achieve deep participation, and neutral enough to invite participation from emerging resources such as demand response and storage, could be why new qualities such as increased flexibility might not be incentivized to the extent needed with high penetrations of variable renewable energy.

Furthermore, to the extent that markets for capacity, energy, and ancillary services interact, design changes in one market could create a disincentive to operate in other markets, such as energy market rules inadvertently removing incentives for participation in certain ancillary service markets (Ela et al. 2012b). In more serious cases, these interactions could create opportunities for market power and market manipulation. Relatedly, too much complexity also could necessitate more frequent market revisions and could weaken transparency (Schleicher-Tappeser 2012).

5.2 Encouraging Investment

In most wholesale markets, energy prices are based on the marginal cost of providing energy, and therefore do not include any of the capital costs of the resources. Investors calculate the risk adjusted returns of potential projects; and as energy prices decrease with increasing penetration of zero dispatch generation sources, other revenue sources become increasingly important,

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[21] Economically efficient refers to providing the lowest-cost solution to meeting the objective—in this case, electricity demand subject to reliability rules.

[22] Some physical factors of electricity systems, for example, reactive power supply and congestion on low-voltage distribution networks, have been deemed too complex to capture and meaningfully improve through market mechanisms. As such, these factors generally have been managed through non-market means.

including scarcity pricing, capacity markets or payments, and bilateral, long-term power purchase agreements. There is debate as to the merit of each.

Price volatility also can complicate cost recovery. Greater penetrations of variable renewable energy could both amplify price swings and make them more frequent (*see* Figure 4). The low marginal costs of wind and solar energy at times could result in extended periods of near-zero marginal prices over large areas, particularly during times when loads are relatively low and the wind and solar resources are plentiful. The variability and uncertainty of wind and solar also could lead to increased frequency of price swings between the near-zero marginal costs of wind and solar and the high price as determined by (a) the availability of transmission capacity, (b) the ability of the balancing authorities to smooth variable renewable supplies, (c) the ability of the balance of the generation fleet or load response to fill in gaps, and (d) the availability of peaking supplies, particularly simple-cycle gas turbines, to complete the response. In areas with significant penetration of variable renewable supplies, their low marginal costs over extended periods and over large areas impacts the recovery of capital costs for that area as well as for conventional supplies.

Nevertheless, clear, long term, transparent policies might provide the strongest long-term investment signals (DB Climate Change Advisors 2009). Denmark for the last 40 years has maintained political agreement on the broad outlines of energy policy. The European Union has semi-certainty until 2020, but a 2030 framework currently is being discussed to send a clear signal about the direction of the energy and climate policy.

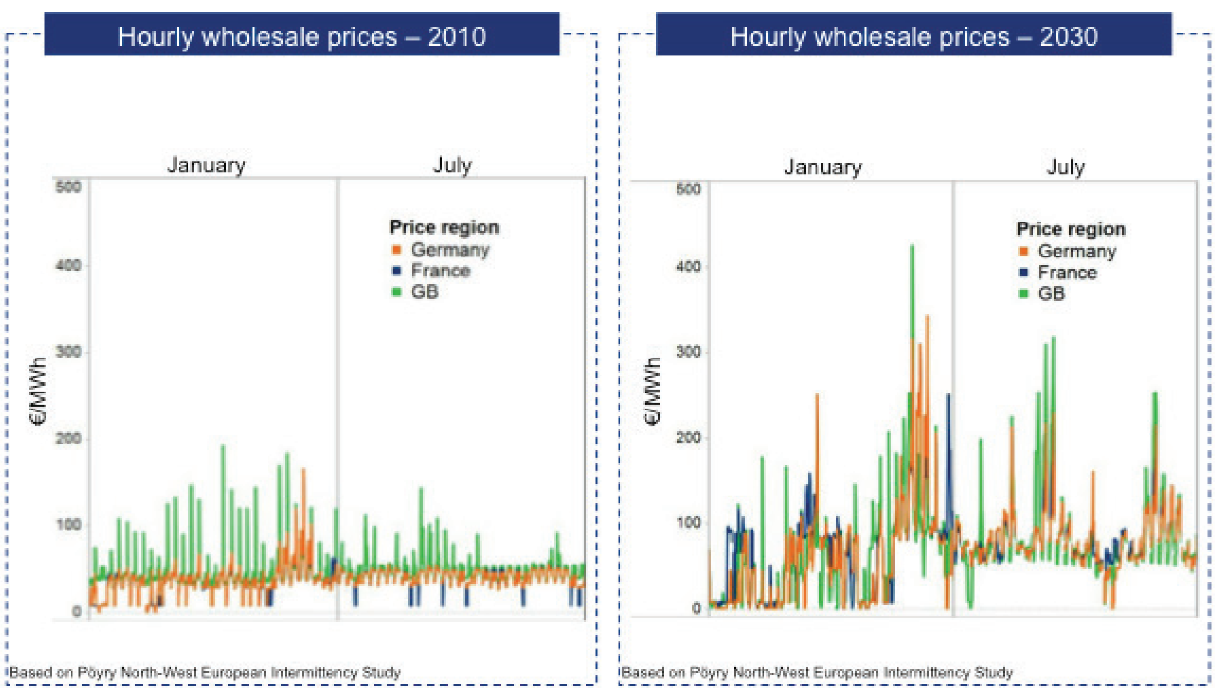

Figure 4. Hourly wholesale prices, 2010 and 2030 (high variable renewable energy).
Poyry North-West European Intermittency Study (2011)

5.3 Harmonizing Across Timescales

A reliable and secure electricity supply requires sensitivity to multiple timescales—from system operations, where milliseconds matter, to capital investments, where decades matter. Electricity markets provide short-term price signals (seconds to days), which are effective at allocating available capacity. In contrast, few power markets provide any long term price visibility and are ineffective at incentivizing the optimal amount of long-term installed capacity to meet reliability (Cramton and Stoft 2006). One difficulty of translating short-term price signals to long-term capacity is that energy markets cannot offer forward revenue certainty, which investors require to reduce risk and to cover fixed costs. Although debt investors remain reluctant to invest in new generation based on existing market products—such as short-term capacity markets—some equity investors are beginning to consider quasi-merchant renewable energy plants (partial power purchase agreement, partial market-based). Nevertheless, these investors require measures to mitigate market risks, such as minimum price levels or electricity or natural gas derivatives as a hedge. Increasingly, renewable energy is viewed as a hedge option against uncertainty (Awerbuch 2006). The incremental investment in capacity is typically smaller than that of a conventional power plant, thus allowing investors to respond more quickly to short-term changes in price signals (Awerbuch 2006; Liebreich 2013). A challenge in market design is how to provide the right mix of market signals to encourage investments in new merchant generation (renewable or otherwise).

5.4 Ensuring Market Depth

As mentioned, market complexity can impede market depth, limiting the impact of market reforms. Yet, there also are many other forces working against market depth. In some markets (e.g., CAISO, MISO, Nord Pool, Central Western Europe Market Coupling), a significant amount of energy is sold through bilateral contracts, which provide long-term revenue certainty for the individual market participants, but remove generators from economic dispatch. Long-term power purchase agreements can be negotiated so that the average energy price allows for capital cost recovery. The implications for systems with high penetration levels of variable renewables but significant bilateral contracts are threefold. First, most energy delivery is purchased months to years in advance, locking in generation that could be inflexible,[23] and leaving a small day-ahead and real-time market for new, innovative, and flexible supply. Second, spot-market prices might be inconsistent with marginal costs due to the limited supply of flexibility. Third, limited participation in the day-ahead and real-time markets can decrease market efficiency by reducing the potential for market software to optimize supply resources based on their bid costs (CAISO 2010b).

[23] Contracts could be modified to support increased flexibility, but this might expose both parties to spot-market pricing, which is inconsistent with the desire to lock-in revenue streams.

6 Market-Design Research As a Platform for International Collaboration

Market-design research increasingly is a fertile platform for international collaboration.[24] Given the range of complex and unanswered questions in this area, it is useful to perform careful analysis of candidate market options prior to their implementation. This is especially important in developing countries that have the chance to construct their energy sector, market, and power system to take into account lessons learned from the rest of the world. Such analytical activities could include the development of the following.

- High-fidelity models to simulate the impact of market design options on power system evolution across a range of timescales, ranging from the millisecond scale (e.g., transient stability analysis) to the decadal scale (e.g., investment-behavior analysis).
- Consultative processes to directly and transparently collect key stakeholder requirements and to provide a platform for ongoing feedback and refinement of market designs.
- Experimental economics studies to more accurately reflect human decision making and strategic behavior as they could influence market evolution (Zhao et al. 2010). Such studies can reveal unintended consequences, such as undesirable interactions driven by incentives or adjacent markets.
- Market performance metrics to guide market-monitoring activities that assess market performance after implementation. A process to revise the market structure should be considered for inclusion in case the market does not perform as desired.

Using these and other methods, several important unanswered questions invite greater near-term international collaboration. Generally speaking, these questions often can be categorized as either short-term (operational) or long-term (planning). Some candidate questions include the following.

6.1 Short-term Operational Timescale

- Are market reforms needed to increase flexibility? If so, are such reforms needed only in some contexts, or is this a general need spanning most markets? To what degree do system characteristics, renewable energy penetration levels, and institutional constraints impact the shape of flexibility-focused market reforms?
- What are the criteria by which price and market mechanisms to reward flexibility are evaluated in an operational setting? Market designers must evaluate competing mechanisms. As an example, probability-weighted pricing has shown promise, and perhaps could internalize risk and flexibility into reserve pricing (Ela and O'Malley 2012). The development of such criteria can guide rigorous evaluation of options.
- How can institutional arrangements unlock, rather than stifle, technical flexibility? For example, to what extent does the presence of significant bilateral contracts impact

[24] Collaborative international efforts include a range of specific projects managed by, for example, the COMITES program of Massachusetts Institute of Technology and Instituto de Investigación Tecnológica Comillas; the Regulatory Assistance Project; and Task 25 of the IEA Wind Implementing Agreement.

flexibility? There is some concern that such contracts—which are valued by investors—might stifle access to technical flexibility. If so, what options exist that could increase flexibility through bilateral contracts that would not violate investor requirements?

6.2 Long-term Planning Timescale

- Of the different types of markets and options (e.g., capacity markets, ancillary services), which fit best with investor requirements? Why? (Compare investor requirements to functionality and risk/certainty that different markets provide.) Are there new innovations that have not yet been adopted that could increase flexibility and meet investor requirements?
- How much capital is available to construct new projects under the current market structures? How does this amount change if new market components/structures are considered? What investor requirements constrain actions by market players? How do these differ by type of investor (e.g., debt vs. equity)? Which actions are constrained (e.g., contract requirements)?
- How does the market behave in its steady state (no growth in variable generation)? If the share of variable generation is increasing, is there a mechanism that is needed to supplement short-run pricing information so that long-term signals can induce more flexibility in the future?
- Are capacity markets desirable and necessary? If so, what designs exist today that are successful and how has this success been measured? The counter-argument for capacity payments or a capacity market is that scarcity pricing would be sufficient to induce needed investment to achieve resource adequacy. A related question concerning scarcity pricing is whether the limited hours and duration of price spikes could be alleviated with a very small number of suppliers, potentially causing enough market power that might result in self-collapsing prices. These are open questions whose answers have not been robustly demonstrated.
- What is the most efficient division of roles between market and regulated components and which criteria should be used to evaluate this? For example, an RTO/ISO determines the need for capacity and the characteristics of that capacity. (How flexible does it need to be?) It then conducts a request for proposal, auction, or other competitive mechanism to acquire the capacity. Or would it be desirable (or even possible) to provide alternative levels of reliability to customers based on their willingness to pay?
- The recommended method for calculating capacity value is effective load-carrying capability (NERC 2009; Keane et al. 2011b). Are there simpler metrics that provide better transparency to market participants? If so, what are they and how do they benchmark against ELCC? How should ELCC be calculated in multi-area power systems with high share of renewable generation?
- How might capacity markets or hybrid constructs be modified to include flexibility requirements?
- How could market designs better value diversity in the generation portfolio and balance low price with low risk? This is particularly an issue for future scenarios that rely heavily

on flexible natural gas to complement variable renewable generation (for more on natural gas, *see* Text Box 11).

- Opportunities to bridge wholesale market designs with emerging technologies, such as demand response, storage, and distributed generation, will depend in part on how utilities can earn profits. How might business models for utilities (or, more generally, electricity service providers) in competitive markets be restructured to more efficiently integrate renewables, demand response, and distributed generation and expand customer empowerment? In a role as "smart integrators," namely a provider of wires, reliability, and integrator of net-metered distributed generation, how can utilities manage portfolio risks? Utilities might have to reevaluate their role for distribution activities just as they did for generation (Brown and Salter 2011).

Similar questions to those listed above could also be asked in regulated markets, where the utility is still vertically integrated and generation comes from the service provider. (Text Box 12 describes priority research questions for China.)

- How can demand response, storage, and distributed generation be properly valued?
- How can flexibility be better valued?
- How can utilities and their regulators better manage risk?
- What lessons can be used from regulated markets and provided to competitive electric-generation supply markets? What lessons can be used from competitive markets and used in regulated generation electricity markets?

Text Box 11. Alignment of Electricity Markets with Natural Gas Markets

The interactions between electricity and natural gas markets introduce a potential reliability concern, and thus have drawn interest from FERC, NERC, ISO-NE, and NYISO, among others. Gas generators, which could play a pivotal near-term role in providing system flexibility, must participate in both electricity and natural gas markets, but they cannot achieve economically efficient solutions in either market due to misalignment of scheduling (Tabors et al. 2012).

Scheduling in natural gas and electricity markets is sequential and is conducted independently. Generators—for example, NYISO, ISO-NE, and PJM—must purchase gas before knowing its electric operating schedule (Tabors et al. 2012). If generators miscalculate and require more or less gas, they have limited options in the illiquid intraday gas market, and likely will pay imbalance penalties. Generators are at even greater risk for scheduling errors around weekends, when gas markets are closed.

Pipeline capacity constraints create further scheduling difficulties and risks to reliability. Pipeline options—a mix of firm and interruptible services—reflect the needs of traditional customers, the local distribution companies, and do not provide much latitude to gas generators, whose schedules are less certain (Lee et al. 2012). The reliance on interruptible service also suggests that gas curtailments, for example those due to weather, might complicate the rising role of gas generation to complement variable renewable energy. Facing pipeline constraints, Xcel Energy has added storage for natural gas to increase its ability to use combined-cycle plants to respond to forecast errors for wind. Short of aligning schedules, RTOs/ISOs might have to consider including gas deliverability in dispatch algorithms (Tabors et al. 2012). Also, financing and construction of new pipelines require firm transmission contracts, typically for 20 years, which are ill-suited for independent power producers operating in day-ahead markets. The gas industry might have to consider alternative approaches to regulating and financing pipeline expansion projects to accommodate the growing customer base of electricity generators (Lee et al. 2012).

Text Box 12. China—Challenges and Research Opportunities in Centrally-Managed Power Systems

Despite several pilot projects for electricity market introduction, the Chinese power system in general is a command-and-control system with a hierarchy of dispatch centers, and with long-term contracts for both power production and use of interconnectors. Although such a system might be suitable in a situation with rapid expansion of conventional (thermal) power plants and little need for flexibility, the Chinese power system today is undergoing a rapid expansion of variable renewable energy. Renewable energy integration aside, various factors are contributing to the desire for a more cost-optimized dispatch of the whole system. Yet, if not solved, problems associated with integration of variable renewable energy—in particular flexibility—will be a major barrier to the Chinese government's ambitions on efficient deployment of renewable energy.

In this sense the challenges for the Chinese power system are similar to the challenges for other power systems that already operate through a competitive power market. Questions about adequacy, energy, and ancillary services currently are under consideration for the design of a control system for the Chinese power system. On top of these challenges, the Chinese system is facing transitional challenges in switching from one control system to another. These primarily institutional and structural issues seem to be a severe hindrance for creating efficient and sustainable solutions.

One high-priority research project would be to conduct detailed stakeholder analyses clarifying benefits and disadvantages (in terms of cost, loss of influence and power, etc.) for the different stakeholders and different control systems. Suggestions for practical first-step solutions should be examined and tested in pilot areas. It would be important to learn from international experiences—to not to copy but rather to leapfrog to a future market setup or control system, thus avoiding the errors and market failures of the present setup in countries with competitive power markets.

Another relevant question for China is how to ensure coordination between grid planning and power expansion planning. This issue is closely related to incentives for establishing new power production and incentives for power system transformation in the future.

7 Conclusion

Experience in many countries illustrates the value in using markets to access flexibility (Cochran et al. 2012). Well-designed markets encourage economically efficient and stable solutions, promote desired behavior, and minimize unintended consequences. Yet, many uncertainties remain about how to evaluate system requirements and effectively induce and sustain investments in appropriate resources. This report reviews market designs that help access flexibility, and it suggests that sources of revenue could shift away from energy toward tailored services.

It is apparent that market design is a difficult task. Many competing objectives must be met, including using short-term price signals to incentivize long-term investments, minimizing market power, and providing incentives for suppliers for the many non-energy services that are needed to balance the grid. Wholesale markets in many locations are markedly uncorrelated with pricing mechanisms in the retail market. This means that participants in the wholesale markets have minimal ability to predict, plan, or account for consumer actions. Further, in some markets with scarcity pricing, spikes in wholesale prices serve only to increase total costs, and do not provide any incentives for consumers to change their behaviors to promote economic efficiency.

The challenge of appropriate market design becomes more apparent in emerging 21st century power systems. Assets such as variable renewable energy, demand response, storage, and distributed generation offer benefits that can be realized throughout the power system—generation, transmission, and distribution—and therefore are difficult to capture in current markets and regulatory structures, which deliberately segregated generation from transmission to support utility unbundling. The power system may require a transformation from a system premised on a strict separation between wholesale and retail, or generation and distribution, to one that can integrate these markets, such that assets from across the system can contribute to flexibility and reliability.

Moreover, market solutions are not the only option. Various hybrid designs—combinations of regulations and competitive markets—might serve as alternatives. A key driver in any market or hybrid design is to start with the characteristics that maximize the value of the power system and ensure that the type and quantity of services that deliver economically efficient operation and design of the power system are understood.

The power system is just that, a *system,* relegating various design and operational issues to entities that are uncoordinated, possess imperfect information, and possess varying degrees of market power. Moreover, these entities operate in a complex market with many economic externalities; thus economies of scope (e.g., coordination of transmission and generation planning) are difficult to achieve. On balance, however, markets can enable efficiency gains that emerge from competitive (or nearly competitive) markets in electricity. Nevertheless, market approaches remain just one option in a broader range of possible approaches, such as vertically integrated utilities.

There is an acute need for international collaboration on wholesale market design questions. A platform for collaborative analysis and modeling will help to evaluate pathways to 21st century power systems. Proposed market or hybrid market-regulation paradigms should be rigorously tested to understand both technical and financial outcomes, but also the alignment with the public policy objectives that drive market design. The 21st Century Power Partnership aims to provide this platform, and the authors of this report sincerely hope that it lays the groundwork for future collaboration.

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