CLEAN GRID VISION:

A U.S. PERSPECTIVE

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CLEAN GRID VISION:
A U.S. PERSPECTIVE

Chapter 5. Global Power Market Trends

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- North China Electric Power University.

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Fatih Birol	International Energy Agency
Roland Brundlinger	Austrian Institute of Technology
Leon Clarke	Pacific Northwest National Laboratory
Laura Cozzi	International Energy Agency
Paolo Frankl	International Energy Agency
Dolf Gielen	International Renewable Energy Agency
Toni Glaser	German Federal Ministry for Economic Affairs and Energy
Hannele Holtinnen	VTT Technical Research Centre of Finland
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Daniel Kammen	University of California, Berkeley
Valerie Karplus	Massachusetts Institute of Technology
Hans Jorgen Koch	Nordic Energy Research
Jiang Lin	Lawrence Berkeley National Laboratory
Mark O'Malley	Energy Systems Integration Group
Lynn Price	Lawrence Berkeley National Laboratory
Martin Schope	German Federal Ministry for Economic Affairs and Energy
Charlie Smith	Energy Systems Integration Group
Ryan Wiser	Lawrence Berkeley National Laboratory

SGERI developed the counterpart report, *Clean Grid Vision—A Chinese Perspective*. The collaborative research with SGERI during the course of the program provided the authors with insights into the Chinese power system and stimulated fresh thinking on some of the common challenges in energy transition.

In addition, this report benefited from thoughtful review by the following individuals at NREL: Douglas J. Arent, John Barnett, Ron Benioff, Jaquelin Cochran, Bethany Frew, Jessica Lau, Trieu Mai, Caitlin Murphy, Yinong Sun. Isabel McCan, Liz Breazeale, Chris Schwing, and Liz Craig provided editing, design, and outreach support. Finally, Elizabeth Weber, Patricia Statwick, and Katie Contos provided critical program support that enabled the daily operation of this multiyear cross-center international program.

Any error or omission in the report is the sole responsibility of the authors.

List of Acronyms

DOE	U.S. Department of Energy
EIM	Energy Imbalance Market
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
FERC	U.S. Federal Energy Regulatory Commission
IEA	International Energy Agency
ISO	independent system operator
LCOE	levelized cost of energy
LMP	locational marginal pricing
NG-CC	natural gas combined cycle
NREL	National Renewable Energy Laboratory
RTO	regional transmission organization
SCED	security-constrained economic dispatch
VRE	variable renewable energy

Preface

The *Clean Grid Vision—A U.S. Perspective* is a part of the National Renewable Energy Laboratory's (NREL)'s 2015–2021 Chinese Programme for a Low-Carbon Future and collaborative research with China's State Grid Energy Research Institute (SGERI). This multiyear program seeks to build capacity and assist Chinese stakeholders to articulate low carbon pathways to achieve energy systems with a high share of renewable energy, energy efficiency, and low carbon emission.

The Clean Grid Vision comprises two major reports: *Clean Grid Vision—A U.S. Perspective*, written by NREL, and *Clean Grid Vision—A Chinese Perspective*, written by SGERI. The former summarizes NREL's lessons learned on some of the main issues in power system transition:

- Power system planning and operational analysis are discussed in Chapter 1, "Clean Grid Scenarios."
- Renewable grid integration challenges and modeling tools at the distribution network level are discussed in Chapter 2, "Distribution Issues and Tools."
- Grid reliability and stability challenges and the technologies to address them at the transmission-network level are discussed in Chapter 3, "Grid-Supporting Technologies."
- Recent dynamics in electricity demand such as energy efficiency, demand response, and electrification are discussed in Chapter 4, "Demand-Side Developments."
- Emerging issues in power market design and market evolution related to the increasing penetration of renewable energy are discussed in Chapter 5, "Power Market Trends."

The scope of *Clean Grid Vision—A U.S. Perspective* is limited to summarizing the main lessons learned and best practices through NREL's power system research in the past 6 years, with a focus on the U.S. power system. It can be compared to and contrasted with SGERI's report that focuses on China's power system.

As a summary report, most of the works cited here were conducted during 2015–2020. While some of the assumptions for these studies, especially the ones related to renewable energy and battery technology costs, are outdated, the main conclusions remain salient and offer valuable insights for planning and operating power systems and power markets with high levels of renewable energy.

More information on the Clean Grid Vision is available at www.nrel.gov/international/clean-grid-vision.html.

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Table of Contents

List of Figures

List of Tables

Chapter 5: Power Market Trends

Highlights

- Integrating markets across a larger geographic footprint can often increase operational efficiency and reduce electricity costs.
- Policies for resource adequacy involve striking a balance between timely grid modernization and getting full value out of old investments. Keeping old units in use too long shrinks the opportunity space for new units, while retiring old units before the end of their useful lives can create stranded costs.
- Markets have accelerated the retirement of coal units in many parts of the world. These units are being replaced by other resources that are both cleaner and less costly to operate than coal units.
- New generation technologies are often less labor-intensive than coal units, which means the transition from coal will have employment effects that will extend beyond the power sector. Many jurisdictions have attempted to cushion the labor effects of power sector transition with policies such as early retirement benefits, retraining workers, and community redevelopment programs.
- Market-based mechanisms to encourage deep decarbonization include energy-based approaches such as a carbon tax on energy prices and capacity-based approaches to reduce the capital cost of zero-emission generation technologies.

5.1 Introduction

Power markets throughout the world are addressing several emerging themes. Some issues are new and were not a concern when markets started to become formally organized a quarter century ago. But there have also been new twists on old issues that are causing some experts to revisit key assumptions about market design. At the same time, technological improvements such as advanced inverters and low-cost storage are expanding the tools that are available to modern power markets. Among the emerging issues in power market design are:

- Redefining reliability, particularly with greater penetrations of wind and solar
- The ongoing problems of revenue sufficiency and resource adequacy, considering how the power sector is changing
- How to account for environmental impacts in bulk power system operations and markets
- Where appropriate, managing the transition of a bulk power system away from legacy generation assets that today might be less economic, and toward new plants that are less expensive to operate.
- Pathways to deep decarbonization and carbon neutrality for electricity generation.

The social benefits of balancing these concerns with market efficiency often spill beyond what current market structures can value. Security-constrained economic dispatch (SCED), a computerized process for using the least-cost resources to meet load, might make retiring an expensive legacy generator a rational business decision, but the economic consequences of doing so might not end there. If the obsolete plant is more labor-intensive than replacement technologies, retiring the plant could seriously impact local economies even though society pays less for electricity.

Similarly, the health and environmental impact of a plant with excessive emissions might not factor into the marginal costs on which SCED outcomes are based. Some governments have created parallel markets for emission trading, and, in many cases, these mechanisms have succeeded in reducing the targeted emissions. More recently, experts have been exploring carbon pricing as an approach to bring emissions directly into the SCED process.

One overall lesson from Chapters 1, 2, and 3 is that the hardest part of finding solutions is not necessarily technical. Methods exist to manage high penetrations of wind and solar generation. The challenge is how to place an appropriate economic value on the flexibility resources needed, how to adapt power markets to incentivize deep decarbonization, and how to make the transition smooth.

This chapter begins by reviewing some of the fundamental assumptions behind power markets. While some of the challenges might be new, crafting a workable market still depends on a number of basic principles. We look at some of the adaptations that have been tried in various markets. We then look at how these new issues can affect paths to next-generation power markets.

5.2 Principles of Power Market Design

5.2.1 Risk and Uncertainty

Vertically integrated utilities made up most of the electric power sector throughout the 20th century. A typical utility-owned generation, transmission, and distribution asset served customers under a monopoly franchise. The government would set the utility's retail rates, approve new power plants and other infrastructure, and regulate the utility's return on investment. The burden of managing risk and uncertainty was largely on the government, so long as the utility prudently managed its business within the bounds of what the government approved.

A wave of electricity restructuring began in the 1990s. Several countries experimented with formal, organized electricity markets to increase economic efficiency and introduce competition. Transmission interconnection and many other aspects of bulk power system operations began to operate under the principle of open access. This allowed entities that were not regulated utilities to provide energy and other services. As more merchant generators entered the market, the burden of managing investment risk began to shift from the public sector to the private sector. Monopolies were no longer protected, and fewer investments were guaranteed a return by the government.

With restructuring, the government no longer sets prices, approves investments, or underwrites financial risk. Its role instead is to ensure the integrity of market competition so that private enterprises can reasonably and rationally manage their own risks. The mechanisms for doing so have evolved through trial and error. But unintended consequences have served as lessons to improve market design and enhance monitoring. Wholesale power markets in many parts of the world have converged on a set of common features:

- Pool-based nodal markets with a two-settlement system for day-ahead and real-time markets
- Co-optimized energy and ancillary services
- Locational marginal pricing (LMP)
- Financial transmission rights markets for financial hedging [1]
- Specific markets or rules to incentivize new investment and long-term resource adequacy.

5.2.2 Unit Commitment and Economic Dispatch

SCED is at the core of all organized electric power markets, as well as many vertically integrated monopoly power systems. The system operators use SCED software to optimize dispatch and achieve the lowest variable operating cost, accounting for all transmission constraints and the operating limits of each generator. The pool available for the market includes planned unit commitments—those scheduled by the plant's operator to be turned on and made available for the next day. The system operator may order the commitment of additional units if voluntary unit commitments are not sufficient to meet forecasted demand and operating reserves.

Economic dispatch is different from the administrative dispatch practices used in some regions in China. Administrative dispatch might prioritize high-efficiency units over lower ones, but there is less computerization used to match actual dispatch with hourly load levels. System operators might have to address manually in real time issues such as transmission congestion and unit ramping limits. Economic dispatch automatically accounts for all these issues simultaneously to meet demand at the lowest total operating cost. The two methods are similar in some ways, but they do not always lead to the same dispatch outcome.

Studies on regional transmission organization (RTO) operations in the United States have found that, compared to self-scheduling of load and generation resources by each individual utility, economic dispatch can reduce wholesale electricity costs by 1% to 5% [2]. Such improvements are driven by three factors: substituting high-cost fuel with lower-cost fuel or with renewable resources that have no fuel cost; greater use of generators with lower heat rates; and reducing or eliminating transaction costs associated with trading between regions within the market.

5.2.2.1 Price Formation

Proper price formation is crucial for ensuring that prices accurately reflect system conditions and incentivize resources needed to meet the changing system conditions. The Federal Energy Regulatory Commission (FERC) has identified four goals of proper price formation:

1. Maximize market surplus for consumers and suppliers
2. Provide correct incentives for parties to follow commitment and dispatch instructions, make efficient investments in facilities and equipment, and maintain reliability
3. Provide transparency so that market participants understand how prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system
4. Ensure that all suppliers have an opportunity to recover their costs [3].

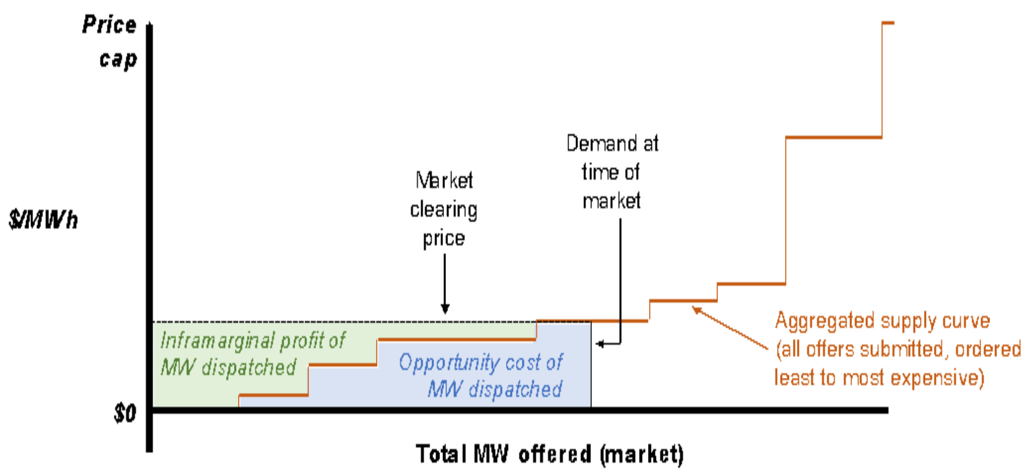

Figure 5- 1. Market clearing price and inframarginal profit

Most RTOs in the United States use market clearing prices, illustrated in Figure 5- 1. In its simplest form, this is the lowest price that will "clear the market"—that is, procure exactly enough energy (or reserve capacity for ancillary services) based on offers submitted by generators. All selected generators are paid the market clearing price, not their offer price. This is different from pay-as-bid auctions, which also select the lowest-priced offers but pay the winners their offer prices.

Generators submit self-priced offers to provide energy or operating reserve capacity,[1] and the clearing price for a particular market period is the level that would procure exactly enough energy or capacity to meet the immediate demand. The clearing price in this simple representation represents the system-wide marginal value of energy (or of capacity for ancillary services), and every generator that is selected is paid the market clearing price.

Inframarginal profit—the difference between the market clearing price and a generator's marginal cost—is an important element of risk management in competitive wholesale power markets. If the market is sufficiently competitive, offers will tend to be priced at the generator's marginal cost of providing the service, resulting in greater inframarginal profits for efficient generators with low marginal costs. Fixed operating costs and finance costs are paid from a generator's inframarginal profit (if there is no other revenue stream); therefore, expectations about prices and inframarginal profit are important factors in the decision to build new generating capacity.

5.2.2.2 LMP

In a market with geographically disaggregated energy pricing, transmission congestion will cause the market clearing price to separate into different LMPs. A major reason for using this type of pricing is that it economically resolves local transmission constraints automatically, eliminating the need for the grid operator to resolve local congestion manually. Figure 5- 2 provides a simple illustration of how line conditions separate a single market clearing price into node-specific LMPs.

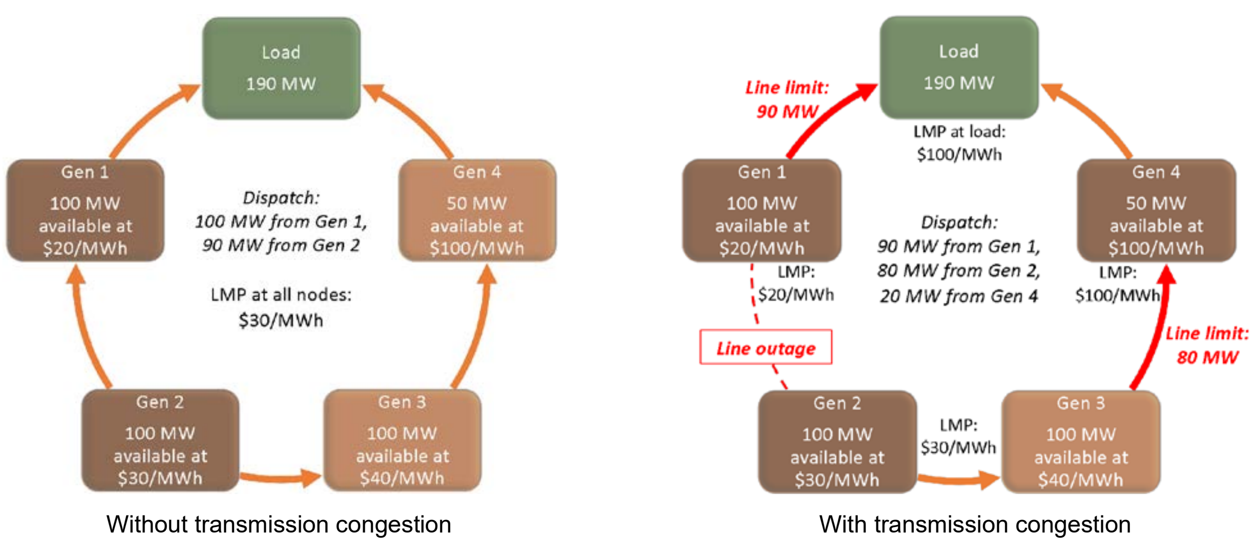

Figure 5- 2. Example of congestion separating a market clearing price into node-specific LMPs

[1] A generation owner who has market power may face certain restrictions that limit its ability to control prices unilaterally.

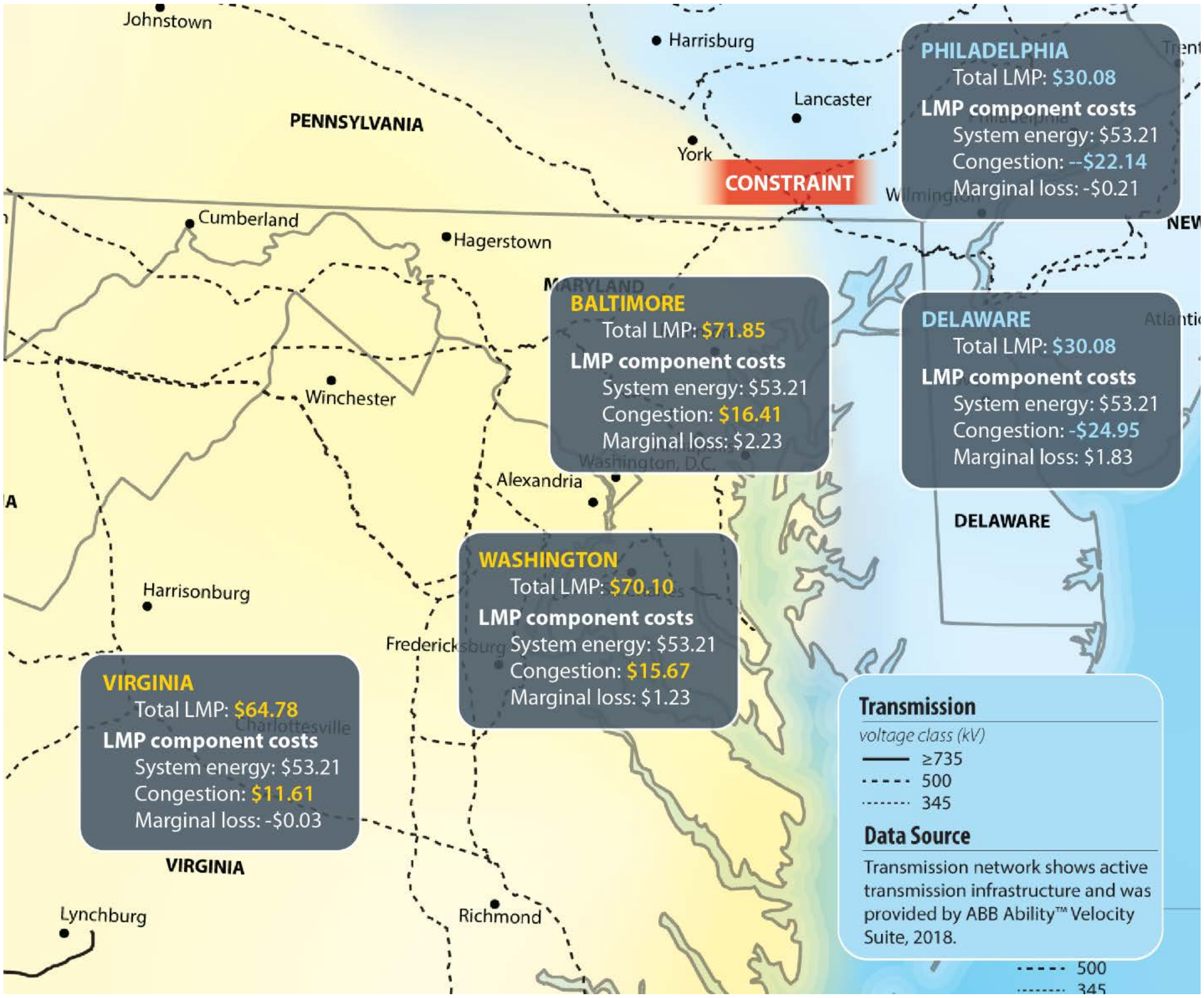

Figure 5- 3. Breakdown of actual real-time LMPs in a portion of PJM (5 p.m. on August 1, 2019)

The LMP has three components, a real example of which is shown in Figure 5- 3.

- The system *energy price* is the marginal cost of energy, given the current dispatch, at the load weighted reference bus. It is the same for every bus in the market.
- The congestion component represents the price of congestion at the bus relative to the reference bus, calculated using the shadow price of binding constraints. It will be zero in a system with no congestion and will vary by location if a system is constrained.
- The *marginal loss* component represents the marginal cost of transmission losses at the bus relative to the reference bus and will vary by location.

Generators account for operational uncertainty and unit flexibility limits in the offers they submit into the market; therefore, LMPs do not necessarily reflect the physical marginal cost of production. Rather, they represent the risk-adjusted economic expectations of marginal costs, including minimum expectations for inframarginal profit. The offers may also include strategic elements, such as below-cost prices at low production levels and above-cost prices at full-capacity production.

5.2.2.3 Congestion Rents

The sum of energy payments by load can be more than the sum of energy payments to generators when congestion causes prices to separate into different LMPs. This gap is the congestion rent. Government policy determines what happens to congestion rent: some or all might be returned to load, or some might be used in mechanisms to financially hedge against congestion-related LMP effects.

In the simple example of congestion shown in Figure 5- 2 (right side), the LMP at the load node is $100 per MWh, making energy payments from load $19,000. Energy dispatched from the least-cost combination of generators—90 MW from Gen 1, 80 MW from Gen 2, and 20 MW from Gen 4, taking transmission limits into account—receives total payments of $6,200, making the congestion rent $12,800. If all congestion rent is returned to load, the net payment from load would be equal to the payments received by generators. Total system costs ($6,200) would be higher than in the example without congestion shown at the left of Figure 5- 2.

Some organized wholesale markets use congestion rents to back financial transmission rights. A utility or load-serving entity that purchases power from a low-cost wind or solar resource might use financial transmission rights to ensure that its delivered energy costs remain low in the event of transmission congestion between the renewable energy plant and the demand center. In some cases, financial transmission rights might be assigned to a utility that had physical transmission rights for a legacy generator prior to the introduction of SCED (which does not accommodate physical transmission rights).

5.2.2.4 Out-of-Merit Dispatch

Occasionally, an RTO might need to manually dispatch a generator to resolve specific real-time problems on the system. Out-of-market instructions from the operator usually receive so-called "make-whole" payments, the cost of which is uplifted as a charge to all load on the system. Reforms on fast-start pricing, uplift payments, shortage pricing, and others related to price formation are underway in the United States. The following are key recent changes:

- In June 2016, FERC required RTOs to align settlement and dispatch intervals, and to trigger shortage pricing for any interval with an energy or operating reserves shortage. This reform aligns prices with dispatch signals and operating needs, which provides appropriate incentives for resource performance [4].
- In November 2016, FERC revised the offer cap in regional wholesale power markets. This effort enhances price formation by reducing the likelihood of artificial price suppression [5].
- In March 2019, PJM filed an updated price formation plan to FERC. The plan proposed an extended LMP method to allow all resources selected for dispatch, including flexible and inflexible units, to set the price [6]. The goal is to ensure efficient pricing incentives to maintain required levels of load-following capability—the ability to adjust output according to changes in load, and to reduce the need for uplift payments.

5.2.3 Market Liquidity and Market Depth

Liquidity and depth are important characteristics of any market. Depth refers to the quantity and size of market transactions—specifically, the degree to which prices remain stable in the event of one large-volume transaction. Liquidity refers to how easily value can move from one type of commodity to another (between energy and ancillary services, for example).

Out-of-market transactions such as must-take generation (a predetermined obligation for a load-serving entity to take power from a specific generator regardless of prices in the rest of the market) can affect the liquidity and depth. For example, output from local run-of-river hydro might not be controllable by dispatchers, but there might be policy or contractual requirements that require the system to take the power, irrespective of other market-based dispatch. Load served by must-take generators reduces the remaining demand that is available for the competitive market, and the suppressed level of demand could distort market prices. Other distortions may come from:

- Generators that are granted special status to run at their minimum stable level at all times to avoid startups and shutdowns and to meet baseload demand or as load-followers
- Bilateral contracts that are precommitted and not available for dispatch
- Self-dispatch generation that a utility commits exclusively to serve a portion of its native load.

Figure 5- 4 illustrates how these resources reduce the total amount of energy that is optimized in the economic dispatch process.

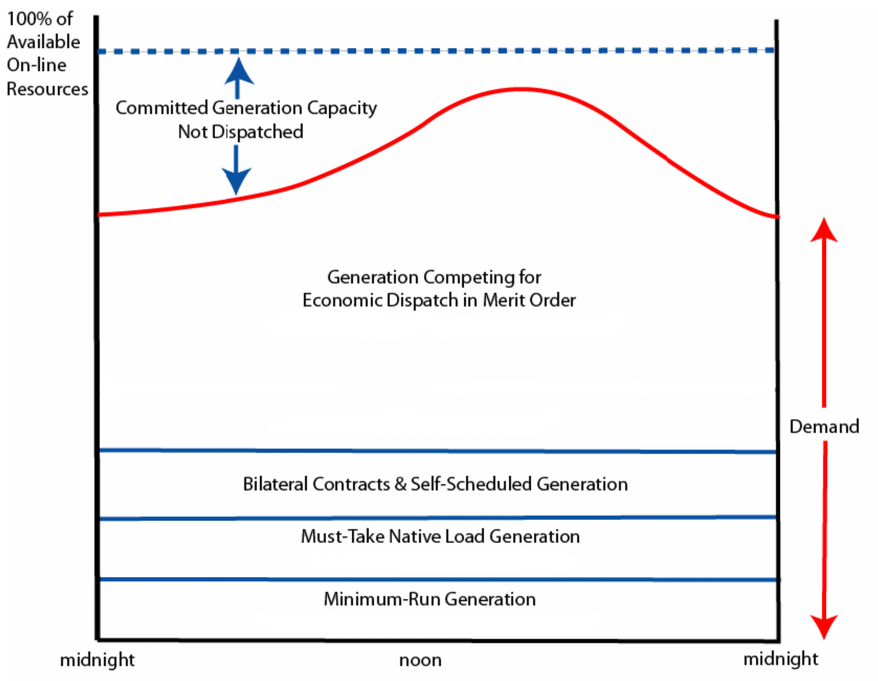

Figure 5- 4. Hypothetical economic dispatch stack

Source: [2]

In U.S. wholesale power markets, the predetermined must-take and baseload units are typically treated as price takers (i.e., cannot set the market price and must accept the market clearing price). The bilateral contracts also receive the market-clearing price and settle the price difference outside of the market. Even so, the physical availability of a sufficiently large amount of must-take and bilaterally contracted energy can suppress market prices and distort investment signals. Investigating the actual effect of these out-of-market resources is an important function of market monitoring (discussed later in this chapter).

In China, a significant amount of energy is sold through physical bilateral contracts with predetermined price and generation curves. Such a setup offers long-term price stability but reduces market participation. The predetermined generation and bilateral contracts have multiple implications. First, the reduced liquidity and market depth could make electricity markets, especially the spot-markets, susceptible to market power (that is, the largest remaining generation owner could have a large enough share of the diminished market that it could control prices) [7]. Second, by locking in generation months or even years in advance, it reduces the total amount of flexible resources in the system and also makes the market smaller for the entry of new and flexible resources. Third, due to the limited resources in the market, the spot-market prices might not reflect the true marginal cost of the system, leading to distorted price signals [8].

Another practice that impacts the liquidity and market depth in China is the layered dispatch system (national, regional, provincial, district, county). While this dispatch practice enhances central planning for certain key resources (such as Three Gorges Dam hydro generation) across the country, it significantly reduces the market depth at the provincial level (the de facto balancing areas in China).

To increase liquidity in the market, some U.S. wholesale power markets have adopted a feature known as “virtual transactions” or “virtual bidding.” Virtual transactions are purely financial bids and offers submitted in the day-ahead market without the intent of delivering or consuming physical power in the real-time market. In PJM, virtual transactions include incremental offers, decrement bids, and up-to-congestion transactions. They are awarded the day-ahead price, and the quantity deviations from the day-ahead market are settled at the real-time spot price [9]. As such, virtual transactions provide market participants a means to hedge against the price differences between day-ahead and real-time markets. This helps improve convergence between day-ahead and real-time prices. Virtual transactions add to the liquidity in the day-ahead market to facilitate settlement of longer-term forward contracts arranged outside the organized dispatch. This added liquidity also helps to moderate or eliminate the ability to exercise market power [10].

5.2.4 Unbundling of Generation, Transmission, and Retail Services

The restructuring of the U.S. electricity sector sometimes includes unbundling vertically integrated utilities. Both the European and the U.S. unbundling started with separating the transmission business from the generation business. During the early-stage liberalization and restructuring of the European electricity markets, the European Commission’s first Electricity Directive allowed the member states to choose their unbundling regime. Unbundling regimes can have the following different stringencies:

1. Accounting unbundling simply keeps separate accounts for the transmission network activities and generation activities to prevent across subsidization while the whole utility remains intact.
2. Functional unbundling requires, in addition to separating accounts, separating the operation and management for transmission and generation activities. This is often referred to as erecting a “wall” between the two parts of the company so that they do not have communication with each other.
3. Legal unbundling requires that transmission and generation be put into separate legal entities.
4. Ownership unbundling requires the generation and transmission to be owned by independent legal entities, which are not allowed to hold shares in both activities.
5. Full unbundling refers to the creation of a separate independent system operator (ISO) that does not own any generation, transmission, or retail services [11], [12].

An important role for the government in the first three types of unbundling is to create and enforce a code of conduct for how the personnel of affiliated entities interact with one another. If the transmission entity were to share privileged information with its affiliated generation entity, all unaffiliated generation companies in the market would be at a competitive disadvantage. The code of conduct may specifically prohibit cross-sharing of personnel, common office space, or the use of common credit where poor performance of the generation unit would degrade the financial position of the transmission unit.[2] For competition between generators to work fairly and efficiently, all dealings between the affiliated transmission and generation entities have to be transparent, arm's-length, and nondiscriminatory (meaning that the transmission entity would treat its affiliate no differently than it would treat any other generation entity).

It was not until 2009 that the European Commission narrowed the unbundling choices to only ownership unbundling and the creation of independent transmission operator or ISO [13]. Therefore, a mix of ownership-unbundled utilities, independent transmission operators, and ISOs are active in the European power markets. U.S. power markets are operated by full ISOs, although in some cases one holding company might own both a regulated transmission utility and an unregulated merchant generator in the same market.

Many countries, including China, have unbundled transmission and generation. The history of unbundling in Europe and the United States has shown that the unbundling of transmission and generation is crucial for achieving competition in the wholesale electricity markets, because it helps to ensure nondiscriminatory access to the networks and to avoid conflicts of interest within vertically integrated utilities [14], [15]. Unbundling is important in eliminating bias in network access and dispatch, improving plant-level operation efficiency and wholesale market efficiency [16], and lowering prices [15], [17].

The unbundling of the retail services from the distribution network has been marked by successes and failures [18]. After its electricity crisis of 2000 and 2001, California rolled back much of its retail electricity reform. By contrast, retail services have been fully unbundled from distribution services in the ERCOT market, where inflation-adjusted retail rates have fallen since 2007.[3] As of the end of 2018, in the 13 U.S. states (and the District of Columbia) with retail electric choice, 10%–50% of residential and 50%–75% of commercial and industrial load were served by competitive (nonutility) retail service providers [19]. Generally, regulators in states with retail competition increase their scrutiny over the market because providers operate differently from regulated utilities. Deceptive practices and "slamming" (changing a customer's service provider without the customer's knowledge) are among the violations that regulators monitor closely.[4]

The unbundling of distribution and retail services has the potential to lower prices, offer customers more options such as green electricity, and stimulate innovative business models, which, for example, can encourage energy efficiency and demand-side participation. But success is not guaranteed. Lessons from the U.S. retail unbundling show that stringent market entry rules are essential. Fair, transparent, and strict market rules with effective market monitoring and swift penalties for misconduct can help avoid deceptive practices and ensure competition [20].

5.3 Pathways to Next-Generation Power Market

5.3.1 Expansion of Market Footprint

The U.S. power markets have been gradually expanding in the past two decades. PJM, for example, started as a power pool with only three utilities in Pennsylvania and New Jersey, and was joined by a

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[2] See, for example, the code of conduct enforced by regulators in Texas during the restructuring of the Electric Reliability Council of Texas (ERCOT) market. Texas Administrative Code §25.272 (Code of Conduct for Electric Utilities and Their Affiliates).

[3] Retail and distribution services remain bundled for municipally owned utilities and most rural electric cooperatives in ERCOT.

[4] For an example of the specific activities monitored by regulators in the ERCOT market, see Texas Administrative Code Subchapter R (Customer Protection Rules for Retail Electric Service).

number of utilities over the years, making it one of the biggest RTOs in the United States, spanning 13 states and the District of Columbia.

As demonstrated in Chapter 1, balancing area cooperation and expansion of the market footprint can bring significant cost savings and operational benefits. A larger balancing area can increase diversity in supply and demand, reduce the volatility in both the load and the variable renewable energy (VRE) output, and thereby reduce the need for reserves [21]. A larger pool of generators also increases the cost-effectiveness of dispatch because a broader customer base can access energy from the most efficient plants. A recent study of the India system that assessed a scenario with 60 GW of wind and 100 GW of solar deployed by 2022 showed that changing from state-level dispatch to a national dispatch could yield an estimated annual system operation cost saving of 3.5% [21]; however, it is important to consider that larger balancing areas may require increased use of transmission over larger distances, so transmission congestion could prevent the system from realizing the full benefits from balancing area cooperation [21].

Balancing area cooperation requires utilization of a variety of grid services taking place over different timescales and providing different levels of VRE integration support. In general, longer-scale resources, such as economic dispatch and unit commitment, can bring the greatest VRE integration benefits but may have the highest implementation costs and complexity (Figure 5- 5).

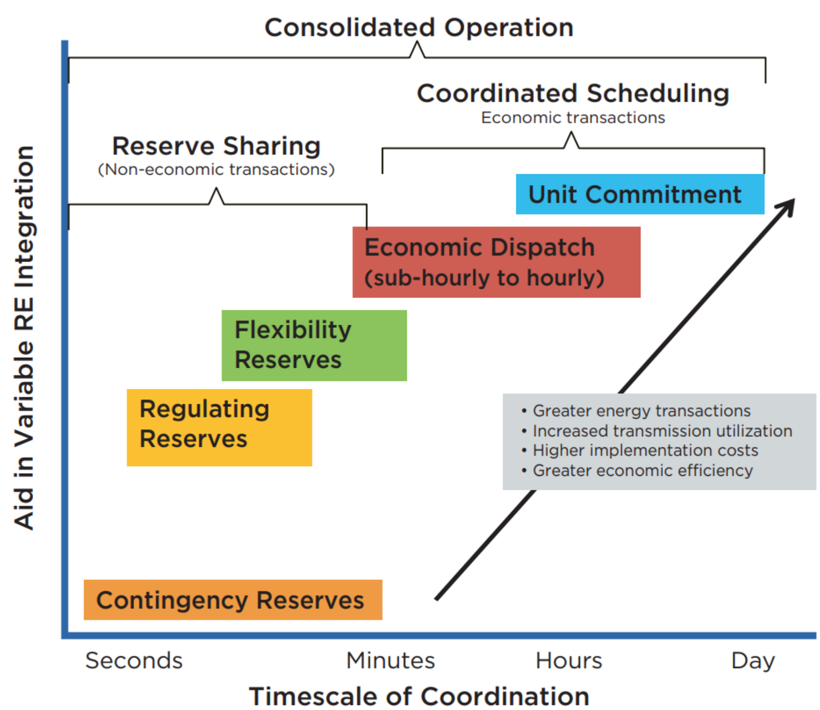

Figure 5- 5. Balancing area coordination over different timescales

Source: [22]

Reserve sharing as a type of cooperation is when the balancing areas define and quantify the estimated total reserve requirements, calculate the actual power flows that can occur at the interfaces, and allocate reserve requirement to each balancing area. Reserve sharing is relatively easy to implement and helps to minimize the impacts of VRE uncertainty.

Coordinated scheduling requires a central system for continuous information exchange of generator availability and costs in the participating balancing areas and mechanisms for monitoring the energy exchanges and transmission usage. Coordinated schedules can be achieved through a bid-based central market or market-facilitated bilateral agreements. It allows for much greater energy exchange, increasing the efficiency of the dispatch and aiding VRE integration, but the monitoring and market mechanisms come with higher implementation costs as the sophistication level increases.

Consolidated operation requires the establishment of an RTO or ISO. In addition to the elements described above, it would also require a complete system of governance and market monitors to investigate and mitigate potential power market issues. It can produce the greatest benefits in terms of overall economic efficiency and VRE integration and brings additional complexity and a steeper learning curve.

Western U.S. EIM

The Energy Imbalance Market (EIM) is an example of coordinated scheduling and operation. In 2014, the California Independent System Operator launched the EIM to conduct real-time trading of the differences between day-ahead forecast of electricity and the actual amount of electricity needed to meet the demand, in other words, the imbalance. The EIM has been expanding since then and now includes portions of Arizona, California, Idaho, Nevada, Oregon, Utah, Washington, and Wyoming. Figure 5- 6 shows the system operators participating in the EIM.

The EIM has shown three types of benefits: more efficient dispatch; reduced renewable energy curtailment; and reduced flexibility ramping reserves needed in all balancing authority areas [23]. Participants have seen $862 million in benefits since the EIM was launched in 2014 [24]. It reduces the flexibility reserve needs across its footprint by around 45% in average. As Table 5- 1 shows, the EIM brings benefits to all its participants, from large participants such as the California Independent System Operator with 42,993 MW of total generation capacity, to smaller participants, such as Puget Sound Energy with 3,500 MW of generation capacity.

EIM achieved these benefits because it can quickly dispatch resources to meet load across a broad geographic region. In addition to the reduction in VRE variability and generation-load imbalance that is inherent in having a larger geographic footprint, it also allows the operator to find the least-cost resources for balancing. The economic dispatch of EIM operates every 5 minutes, resulting in a more economic balancing than if regulating resources were used for all imbalances inside an hour [27].

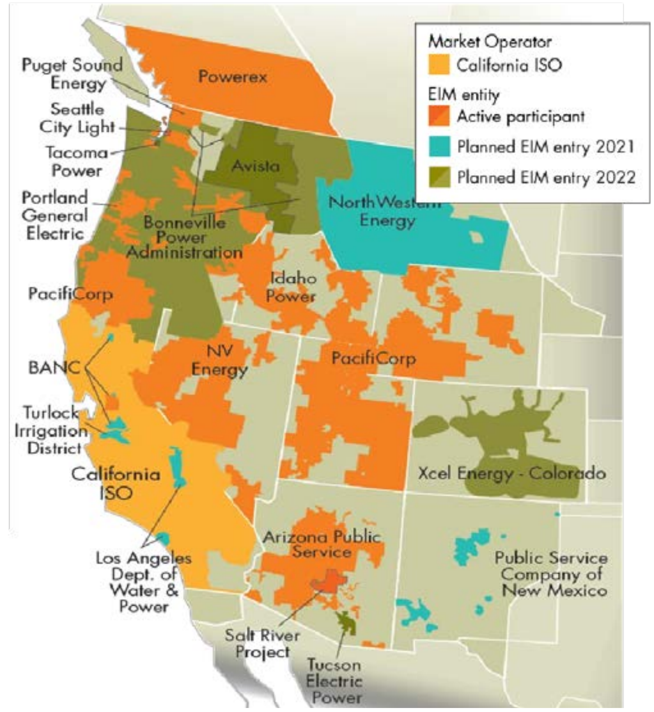

Figure 5- 6. EIM participating utilities

Table 5- 1. Benefits to EIM Participants

	Entered EIM	Benefit Since Entering ($ millions)
Arizona Public Service	2016	$140
BANC	2019	16
California Independent System Operator	2014	192
Idaho Power	2018	55
NV Energy	2015	89
PacifiCorp	2014	235
Portland General	2017	73
Powerex	2018	20
Puget Sound Energy	2016	41

Source: [23]–[26]

5.3.2 Long-Term Resource Adequacy

Long-term resource adequacy—the ability to provide sufficient resources to meet projected demand at low cost—is important for any power system. When the reserve margin of a system becomes too small, a regulated utility will need to identify the least-cost options for procuring new capacity. Regulators review, select, and approve the best option, then the utility procures the new capacity. Because the utility is the sole provider for its market, regulators can include in all retail rates a guaranteed return on the utility's investment.

A competitive market, in contrast, relies on price signals to provide economic incentives for investing in new capacity. Every competitive power producer calculates the potential cost and revenues for a new plant on their own, based on their projection of market conditions (including future fuel cost, wholesale power price, and so on). The power producers are responsible for their own risk assessment and are not guaranteed a return on their investment. Instead of a centralized integrated resource planning process, the power market produces price signals and associated profit expectations to build new generation capacity or retire old capacity in a decentralized fashion, thus achieving long-run efficiency [28].

The growth of zero-marginal-cost VRE could lead to sustained periods of low wholesale prices. This could reduce the economic incentives for investment in new resources necessary for reliability [28], [29]. Conventional units with higher marginal costs would be dispatched less often (or not at all), and the lower-cost conventional units that would continue to be dispatched would have smaller inframarginal profits to cover their fixed costs. This is known as the merit order effect. In extreme cases, it can lead to negative LMPs during periods when system-wide load is low and VREs make up most of the capacity that is dispatched [30], [31].[5]

5.3.2.1 Forward Capacity Markets

U.S. wholesale power markets rely on different mechanisms (including capacity markets or payments) to meet their resource adequacy requirements [32]–[34]. Four out of the seven U.S. power markets have forward capacity markets, which use auction mechanisms to ensure that new generation capacity is built to meet resource adequacy and help resources recover their capital costs. Table 5- 2 summarizes the general features of the capacity markets in PJM, ISO-NE, MISO, and NYISO. They vary in terms of the slope of the demand curve, the time horizon for which they secure capacity, and resource qualification criteria. They typically have a price cap that is equal to the annualized capital cost of a new peaking plant.

Under the resource neutrality principle, all qualified resources (VRE, demand response, storage, and so on) should be allowed to participate in these capacity markets. In fact, most demand response resources participate in the capacity markets. And FERC Order 841 instructed the RTOs/ISOs to allow nondiscriminatory participation of energy storage in the wholesale energy, capacity, and ancillary service markets [35]. VRE can provide capacity, but the quantification of their capacity credit (i.e., how much of their nameplate capacity can contribute to system adequacy) is complex due to their variability, uncertainty, and declining capacity credit—especially of solar—at higher penetrations [56]. The U.S. power markets have different methods for qualifying VRE capacity credits, and the results reflect their particular system configuration and geographical locations (Table 5- 3).

[5]Studies showed that, despite the occurrence of negative pricing, the average wholesale price is affected less by VRE and more by low fuel costs for natural gas units. Flat load growth also affects wholesale prices [29], [36].

Table 5- 2. Table Capacity Market Designs in U.S. Power Markets

RTO/ISO	Capacity Procurement	Auctions	Planning Horizon	Must Offer and Bidding Provisions	Product
PJM	Centralized market	Base residual auction	3 years prior to annual delivery	Day-ahead market	Generic MW
	Forward contract	Incremental auction	20, 10, and 3 months prior to annual delivery		
ISO-NE	Centralized market	Forward capacity auction	3 years prior to annual delivery	Day-ahead and real-time markets; must schedule maintenance with ISO	Generic MW
	Capacity contract with financial call option for energy	Annual reconfiguration auctions	24/8/3 months prior to annual delivery		
		Monthly reconfiguration auction	2 months prior to monthly delivery		
MISO	Resource adequacy requirement: bilateral contracts or voluntary centralized market	Planning resource auction	1 year prior to annual delivery	Day-ahead market; also applies to VRE and participating external resources	Unforced capacity (i.e., installed capacity derated for the expected level of outage during high-demand periods)
	Forward contract				
NYISO	Centralized market; forward contract	Capability period auction/strip auction (6 months)	30 days prior to 6-month delivery	Day-ahead market	Unforced capacity
		Monthly auction	For any remaining month in 6-month capability period		
		Spot market auction	For upcoming month only		

Source: [33]

Table 5- 3. Recent VRE Capacity Credits in U.S. Markets

ISO	Wind	Solar
PJM	14.7–17.6%	38%–60%
ISO-NE	9%–18% (summer)	27%–33% (summer)
MISO	15.6%	50%
NYISO	10% (summer) 30% (winter) 38% (offshore, both seasons)	26%–46% (summer) 0–2% (winter)

Source: [33]

5.3.2.2 Resource Adequacy Requirements

Instead of using capacity markets, the California Independent System Operator and the Southwest Power Pool impose resource adequacy requirements on load-serving utilities. In its 2015 tariff revision, the California Independent System Operator required load-serving entities to procure sufficient capacity to meet flexibility requirements, in additional to conventional resource adequacy requirements, within their capacity mix [37]. This represents an administrative and centralized planning approach to ensure resource adequacy.

5.3.2.3 Resource Adequacy in ERCOT's Energy-Only Market

ERCOT, on the other hand, has an energy-only market with a high price cap ($9,000/MWh). It also has a real-time price adder that reflects the marginal value of available operating reserves. These two tools provide a strong incentive: if a resource in ERCOT is unavailable when prices are high, it loses the scarcity revenues and may not achieve cost recovery [33]. In other words, ERCOT attempts to address the "missing money" problem directly through scarcity pricing in the nodal energy market—price incentives to maintain reliability without fundamentally altering the energy-only market design.

The $9,000/MWh price cap includes a duration limit: when the imputed net operating margin of a peaking plant exceeds three times the cost of new entry for new generation plants, the price cap falls to $2,000/MWh.[6] Calculations take place over one calendar year.

ERCOT's innovation was to introduce the operating reserve demand curve that, among other effects, helped mitigate missing demand participation [38].With the implementation of the operating reserve demand curve, wholesale prices in the real-time energy market will increase automatically as available operating reserves decrease. As illustrated in Figure 5- 7, the value of the operating reserve demand curve at any given level of available operating reserve is determined as the loss of load probability (the time period of power shortage in a year) at that reserve level multiplied by the value of lost load (set at $9,000/MWh in ERCOT).[7] For each season, ERCOT creates six such demand curves representing six 4-hour blocks in each day, capturing the seasonal and diurnal variance in system conditions. When

[6] For more information, see Texas Administrative Code §25.505(g) (Reporting Requirements and the Scarcity Pricing Mechanism in the Electric Reliability Council of Texas Power Region).

[7] The mathematical methodology of the operating reserve demand curve can be found at "Methodology for Implementing ORDC to Calculate Real-Time Reserve Price Adder," ERCOT, 2019. http://www.ercot.com/content/wcm/key_documents_lists/89286/Methodology_for_Implementing_ORDC_to_Calculate_Real-Time_Reserve_Price_Adder.zip.

operating reserves drop to 2,000 MW or less, this demand curve automatically adjusts energy prices to the established value of lost load.

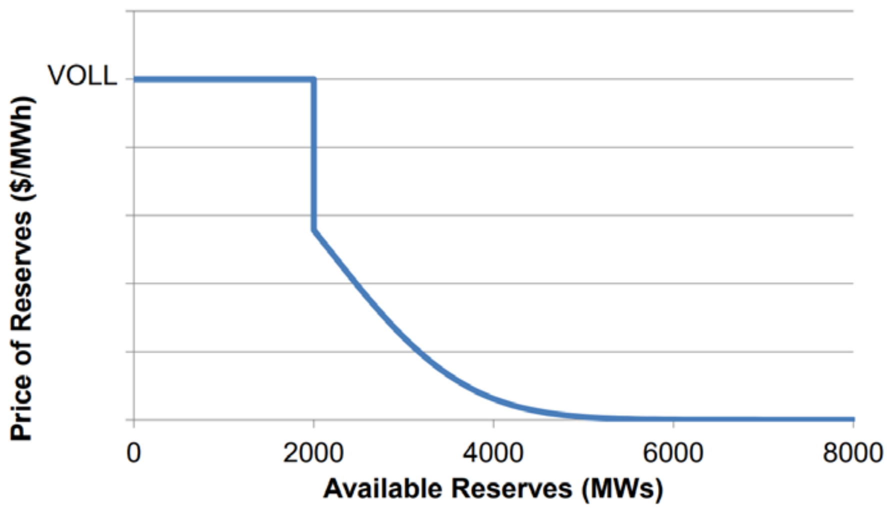

Figure 5- 7. Illustration of ERCOT's operating reserve demand curve

Source: [39]

5.3.3 Retiring Old Plants

The gap between energy revenues and total cost (variable operating costs plus fixed costs and the costs of capital financing) is often called the missing money problem. It predates the large-scale expansion of renewables and is believed to be a result of many issues: consumers being shielded from price swings; the existence of price caps; inadequate scarcity pricing; and the inability of customers to purchase different levels of reliability under the same interconnected power system [40]. But neither a forward capacity market nor scarcity pricing can rescue old, inefficient plants that cannot compete economically with new, efficient plants.

The United States saw its second- and third-largest annual totals for coal plant retirements in 2018 and 2019 [59]. Most of these retirements occurred in RTOs, where the widespread use of markets provided transparent quantification of the impaired value of old coal plants.

Regulatory filings by Vistra Energy, one of the largest independent power producers in the United States, highlight both the nationwide changes in the market and the business responses to those changes. Vistra decided to retire three large coal plants in ERCOT in 2018 while it acquired a natural gas combined cycle (NG-CC) plant and a solar plant. The company determined that the three coal plants were no longer economically viable, calculating that the impaired value of these assets and one other coal plant not retired—in all, 7.2 GW of capacity—was $2.5 billion [42].

Navajo Generating Station

The decommissioning of the Navajo Generating Station, the largest coal-fired power plant operating in the western United States, provides a useful case study for these workforce transition considerations during the energy transition.

The Navajo Generating Station was a three-unit, 2,250 MW coal-fired power plant owned by utilities Salt River Project, Arizona Public Service Co., NV Energy, and Tucson Electric Power. A portion of the share owned by Salt River Project was obligated to the U.S. government to provide electricity for operating the pumps to deliver most of Arizona's share water from the Colorado River. The Navajo Generating Station employed nearly 500 full-time employees, more than 90% of whom were Navajo.

In February 2017, the utility owners of the plant expressed their intent to not operate the facility after the end of the existing lease term on December 22, 2019. Since then, the U.S. Department of Interior has explored options for the long-term future of the Navajo Generating Station. In addition to the utilities' integrated resource plans, NREL conducted a series of studies [41], [16] for the U.S. Department of Interior to investigate the sectoral, technical, and economic trends that were likely to affect future operations of the plant and new energy development by Native American tribes in Arizona.

Analysis showed that low natural gas prices had made the Navajo Generating Station uneconomic relative to other available resources. From 2015 through 2018, power from the Navajo Generating Station cost customers nearly $100 million more than what the same amount of energy would have cost had it come from surplus capacity on existing NG-CC units.

During the time preceding the plant's retirement, the owners reassigned some employees to other operations, offered early retirement to some eligible workers, and offered severance packages to others. Apart from key managers, the plant was being operated entirely by short-term contract employees during the months prior to full shutdown. *Image source: David Hurlbut, NREL*

In accounting, impairment means “the carrying amount of a long-lived asset ... is not recoverable and exceeds its fair value. The carrying amount of a long-lived asset ... is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset” [60]. Under generally accepted accounting principles, the company would reduce the impaired asset’s value on its balance sheet and record the impairment as a loss against revenues. In this case, Vistra conducted a net present value analysis of future revenues (based on forecasted natural gas prices and wholesale power prices), the plants’ operating costs, and the cost of carrying the assets on Vistra’s books. The impairment analysis resulted in a reduction of the plants’ asset value and a one-time charge to net earnings [42].

The company said that:

> [b]ecause our baseload generating units and a substantial portion of our load following generating units are nuclear-, lignite- and coal-fueled, our results of operations and operating cash flows have been negatively impacted by the effect of low natural gas prices on wholesale electricity prices without a significant decrease in our operating cost inputs. Various industry experts expect this supply/demand imbalance to persist for a number of years, thereby depressing natural gas prices for a long-term period. As a result, the financial results from, and the value of, our generation assets could remain depressed or could materially decrease in the future unless natural gas prices rebound materially. [42]

5.3.4 Workforce Considerations

As countries transition from a fossil-fuel dominated power system to one dominated by inverter-based technologies (e.g., wind and solar PV), the effects of such transition ripple through socio-economic spheres. One of the issues countries have to consider is the workforce transition. According to the *Quadrennial Energy Review*, 141,500 domestic coal jobs were lost between 1985 and 2016; the industry shrank by 60% and is forecast to continue declining over the coming decades. On the other hand, “job growth in renewable energy is particularly strong” [43]. From 2010 to 2015, the solar industry created 115,000 new jobs. In 2016, approximately 374,000 individuals worked, in whole or in part, for solar firms. There were an additional 102,000 workers employed at wind firms [43].

Issues related to employment are often difficult to address and politically sensitive. A coal worker often cannot transition smoothly to a position in the renewable industry without additional training [44]. And while coal mining and processing is often centralized and has created robust employment and a sense of identity in mining towns, the renewable energy industry—from manufacturing, financing, development, installation, and operation and maintenance—is often decentralized. Therefore, managing the workforce transition requires political prowess, financial investment, and attention to equity and cultural factors [45].

Literature on economic transition showed that it is important for local economies to develop a transition investment strategy that may include local revenue strategies, state and federal assistance, and a spending strategy linked directly to their economic development and workforce goals [46]. Colorado promulgated a law in 2019 that requires the utility to submit workforce transition and community assistance plans if it plans to accelerate retirement of any existing generating facilities [47]. The law requires these plans to include detailed information on the number of workers who will be retained, transferred to other electric generation facilities, retrained for a new position, retired as planned or early, and so on. Such requirements ensure utilities plan for workforce transition prudently as they embark on the energy transition.

As the energy sector transitions from coal to renewables, research on coal-to-solar retraining showed that in the scenario of a complete elimination of the coal industry in the United States, the total retraining costs of coal-specific jobs to solar jobs would cost $180 million, while retraining all coal-related jobs would cost $1.87 billion, which could be supported through self-payment, company sponsorship, state programs, or federal funding [44]. But not all coal jobs would necessarily remain in the energy sector. Local transition strategies may identify other areas of investment central for both economic development and workforce placement such as infrastructure, quality of life amenities, schools, or health services.

The transition occurs over time, so companies can prepare for the transition ahead of time. American Electric Power, for example, started preparing, in 2012, for the 570 jobs that would be lost by 2016 due to plant closure. During this period, the company allowed positions to remain vacant after normal retirements and exits in these plants. When plants shut down, almost half of the employees moved to similar positions at other plants with some retraining, and many were eligible for retirement [43].

5.3.5 Market Monitoring in an Increasingly Complex Market

As previously described, sending reliable price signals to motivate efficient generation and investment is the principle behind all market designs. If prices are artificially manipulated and thus fail to reflect real supply and demand, the consequences can be costly. As markets expand and evolve, the complexity of the markets has greatly increased, making market monitoring all the more important. Market monitoring keeps a close watch on the efficiency and the effectiveness of the markets and helps to ensure that all market players behave appropriately and do not abuse their market power [48]. All U.S. power markets have market monitoring units. FERC defined the market monitoring units' tasks as follows:

- "To identify ineffective market rules and tariff provisions and recommend proposed rule and tariff changes to the ISO/RTO that promote wholesale competition and efficient market behavior.
- To review and report on the performance of wholesale markets in achieving customer benefits.
- To provide support to the ISO/RTO in the administration of Commission-approved tariff provisions related to markets administered by the ISO/RTO (e.g., day-ahead and real-time markets)
- To identify instances in which a market participant's behavior may require investigation and evaluation to determine whether a tariff violation has occurred, or may be a potential Market Behavior Rule violation, and immediately notify appropriate Commission staff for possible investigation" [49].

Research [50] showed that it is important to create a market monitoring unit prior to actually implementing the wholesale markets. This means putting in place confidentiality protocols, procedures for data access, appropriate information monitoring systems, and complaint procedures prior to market opening. The market monitoring unit needs to:

1. Be independent from the market participants, which means it cannot be involved in any generation, transmission, or load-serving business, and to the extent possible, function independently from the ISO/RTO itself
2. Be staffed by people from diverse expertise (e.g., power engineering, economics, data science) and with a core understanding of electric power market structure, grid infrastructure, and grid operations
3. Have the capacity and the mandate to scrutinize market data in a timely manner, which makes automation of short-term monitoring activities essential
4. Have the resources and communication skills to convey results and findings to all stakeholders (e.g., market participants, policymakers, the general public) [50], [51].

A major function of market monitoring is to deter market power abuse and market manipulation. Market power is when one supplier, or a group of suppliers acting in collusion, owns or controls a share of total supply large enough to control prices. In general, market power can be exercised in two ways—economic withholding or physical withholding. Economic withholding is when the supplier bids excessively above the marginal cost of production and drives up the price. Physical withholding is when the supplier withholds some of its available capacity from the market, thus driving up the price it receives for the rest of its portfolio due to the shortage in total supply. To do so, the supplier may schedule or bid only a part of its available capacity or declare false unit outages [52]. Table 5- 4 provides the basic techniques to detect market power. Details of these techniques and how to apply them can be found at [53]–[56].

Table 5- 4. Categories of Market Power Detection Techniques

	Ex-Ante	Ex-Post
Long-Term Analysis	• Structural indices (e.g., market share, Herfindahl-Hirschman Index, residual supply index) • Simulation models of strategic behavior.	• Competitive benchmark analysis based on historical costs • Comparison of market bids with profit maximizing bids.
Short-Term Analysis	• Bid screens comparing bids to reference bids • Some use of structural indices such as pivotal supplier indicator and congestion indicator.	• Forced outage analysis and audits • Residual demand analysis.

Source: [54]

Having market power without exercising it does not necessarily compromise the market. Conversely, market participants without market power may also engage in market manipulation that can harm consumers, render prices inaccurate and unreliable, and interfere with market operation. What is important is the market participant's behavior. Regulators, as well as the general public, became acutely aware of this after the Western energy crisis of 2000–2001 when Enron and several other companies conducted a variety of manipulative schemes that wreaked havoc on the energy markets. While detecting market power could be relatively straightforward using techniques mentioned earlier, detecting market manipulation is more difficult. It is not possible to provide an exhaustive list of manipulative schemes, but we can list several ways market manipulation may happen:

1. Cross-market manipulation is when market participant trades in one market with the intent to move prices in a certain direction to benefit positions in a related market. This is the type of scheme that happened during the Western energy crisis and continues today in trading physical gas to affect index prices and in trading physical or virtual power to influence financial transmission rights [57].
2. Gaming is when market participant circumvents or takes unfair advantage of market rules or conditions in a deceptive manner that harms the proper function of the market and potentially other market participants or consumers [57]. This can include intentionally submitting bids that

falsely appear economic to the market software, but in fact aim at receiving premium rates for the artificial condition they create.[8]

3. Misrepresentations and omissions of information.

Even the world's most advanced power markets seek ways to continually improve operation. Market monitoring provides a continuous and systematic review of market outcomes to improve efficiency and deter abusive behavior. As markets evolve in scale and complexity, robust and independent market monitoring is on the frontline of ensuring price integrity and market competitiveness.

5.3.6 Deep Decarbonization

Power markets throughout the world are taking a variety of approaches to decarbonizing electricity production. Most approaches fall into one of two categories.

- Energy-based approaches, where the price of energy includes some type of adder based on CO_2 emissions, or a price subsidy for eligible new technologies

- Capacity-based approaches, where renewables and other low-emitting technologies receive incentives that reduce capital costs.

Energy approaches include carbon taxes, carbon pricing, and tax credits for electricity produced by qualifying renewable energy resources. Carbon pricing increases the effective marginal cost of coal and natural gas generation relative to nuclear, hydropower, and renewables. Depending on the shape of the overall supply curve, this can reduce the number of hours that carbon-intensive generators are deployed through SCED. Similarly, price subsidies for renewables allows these technologies to reduce their offer prices in SCED, which can accelerate the replacement of carbon-intensive generation with renewables.

Capacity approaches subsidize the investment costs of renewables. This reduces a new plant's levelized cost of energy (LCOE), enabling the owner to accept lower negotiated energy prices and still earn a return on investment. This has been the primary tool used by solar and geothermal developers in the United States and is being used more by wind developers as energy-based subsidies are reduced.

Many low-emission technologies such as wind, solar, and hydropower have zero or near-zero marginal cost. As more of these resources replace more coal, oil, and natural gas in SCED, the energy prices that clear the market could over time become too low to sustain investment in new capacity. A hybrid approach that has evolved in some markets combines bilateral supply contracts and SCED-based LMPs. The contract between the developer and the load-serving entity provides a consistent payment, with adjustments based on LMPs at the generator's grid node.

5.4 Conclusion

The evolution of the electricity sector toward competitive modern markets is occurring over a long period and responding to rapid changes in technologies, business models, and other market factors. No reformed power market anywhere in the world looks the same today as it did a decade ago. Technology has enabled some of the evolution, but perhaps it is more important that people and institutions learn from experience how to make markets better over time. Governments still have an important role—not as the authority controlling prices, but as the authority safeguarding the integrity of the economic processes that create prices in response to supply and demand and ensuring reliability and other objectives are met.

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[8] For more information on the JP Morgan case, see FERC "Order Approving Stipulation and Consent Agreement" [58].

More VRE resources will change market conditions, but they will not change market fundamentals. Prices provide important signals for new investments and how the grid operates—including new technologies and processes discussed elsewhere in this report. If poor market design or the exercise of market power by a large entity distort these signals, outcomes will cease to be efficient and the public will bear the additional cost. Fundamentally, prices reflect supply, demand, and the cost of technological options.

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