Design of Efficient Generation Markets

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Invited Paper

The design of spot markets for generation services, such as energy, regulation, and operating reserves, and longer term markets for capacity, remain in evolution in many countries. Market design includes definition of the service, bid, or offer requirements, and rules for pricing and financial settlement. In the United States, most organized regional markets have converged on similar elements of spot market design. The design of capacity markets remains in flux. Market power mitigation is currently a regulatory requirement in the United States, and experience with different methods shows that it must be carefully aligned with market design to ensure both efficient pricing and efficient investment. This paper surveys these topics and their relationships to each other and identifies researchable issues.

Keywords*—*Ancillary services, auctions, capacity, generation markets, market design, market power, power system economics.

I. INTRODUCTION

The goal of regulatory reform of the electricity industry around the world has been to achieve greater efficiency in provision of generation services through market competition. Whereas generation was widely believed before the 1970s to be part of a natural monopoly, technological developments since then have made scale economies in generation construction and operation less important, particularly in large, well-interconnected markets. At the same time, some very costly and inefficient investments in generation approved under franchised monopoly regulation suggested that competitive markets could make better decisions. Thus, competition among suppliers of generation came to be seen as a viable alternative for spurring efficiency in electricity production. Regulatory reform started in the United States in 1978 with the passage of the Public Utility Regulatory Policies Act, and began overseas with power market restructurings in Chile (1982) and in England and Wales (1989). In the United States, regulatory reform was accelerated over the latter half of the 1990s with the advent of the open access transmission regime in 1996 [1] and the subsequent formation of several large regional spot markets under independent system operators (ISOs) and, later, regional transmission organizations (RTOs) (for our purposes, ISOs and RTOs are basically the same type of organization, and we will use the term ISO generically).

In general, efficient markets often require complex market designs or rules [2]. In the case of electricity, market rules attempt in particular to provide for: 1) consistency between the reliable physical operation of the system and the forward and spot market pricing of generation services; 2) price-based congestion management; 3) the allocation and trading of transmission property rights; and, increasingly, 4) longer term planning functions and markets to support investment. In the United States, the market rules also include various approaches to market power mitigation, under the *Federal Power Act* (FPA) requirement that wholesale prices remain "just and reasonable"—i.e., reflective of competitive market outcomes. Other market design models are also possible and will be discussed below.

Generation market designs have been evolutionary both in the United States and in several other countries. Some prominent questions on how to achieve economic efficiency and market completeness through design have included the following:

- whether spot generation markets (day-ahead and real-time) and transmission system operations should be integrated through central auctions that recognized all relevant system constraints, or if they should be decoupled to facilitate decentralized forward trading of energy under more typical commodity trading rules;
- how many different generation services should be defined and priced through markets and how to account

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for complementarities and substitutions among those services;
- how differentiated the prices need to be over space for energy, operating reserves, and capacity;
- whether nonconvex bids for supply spot offers, including, e.g., start-up and minimum load costs, are necessary;
- whether in the absence of price responsive demand, the spot market design should provide administrative scarcity pricing based on the expected value of lost load or other measures;
- what limits on the exercise of market power are needed and in which circumstances;
- whether there can be efficient investment in the absence of price responsive demand and the presence of market power mitigation, and, if not, whether forward reserve markets or capacity markets will lead to such investment.

This set of issues in generation market design is the concern of this paper. While we do not provide detailed case studies of particular markets, we do refer in many instances to the market design experiences of several countries, with an emphasis on the United States. Also, several other relevant topics of increasing importance, such as regional planning processes to integrate generation and transmission investments, are not discussed.

A. Electricity Market Organization

Although our focus is generation market design, the choice of organization for market functions and system operations has significant implications for our subject. Three general alternatives have been identified (here we follow [3], but see also [4], [5]).

1) Integrated or Centralized Spot Auction Markets: The first is an integrated, centrally optimized day-ahead and real-time auction market design. (We refer to both markets collectively as the spot market because, although the day-ahead market is a forward, or financial, market, almost all supply is typically required to be scheduled through this market under prevailing rules). "Integrated" means that one entity optimizes all the offers of supply into the spot generation markets and transmission system operations simultaneously, as is characteristic of the U.S. east coast ISO markets. In the extreme case, all transactions go through the auction ("Poolco"), as in the first England and Wales market design, but most such U.S. markets allow bilateral and "self-scheduled" transactions to coexist with central auctions. Spot market pricing of energy and congestion can be done through zonal pricing, but most U.S. ISO markets have converged on locational marginal pricing, as described below. Depending on the market design, the market/system operator also allocates or auctions (e.g., annually, monthly) transmission property rights that are consistent with locational pricing of spot power, such as the financial "point-to-point" transmission rights in the eastern U.S. markets. Such rights could also be flowgate rights [6].

2) Separated Markets: A second approach to market organization is to separate generation markets and transmission system operations to the degree possible, requiring most energy trading to take place through bilateral forward contracting or through multilateral exchanges. This is often characterized as a "decentralized" market design. The system operator is restricted to energy balancing and provision of ancillary services, and these market functions can be minimized through "balanced scheduling" requirements (forward schedules in which supply equals demand). The primary U.S. experience with such a design was the early California market, with its separate day-ahead Power Exchange (PX) and ISO. In that market, the PX cleared two large zonal submarkets on the basis of energy-only offers and with no physical generator constraints (e.g., ramp rates). The ISO was then required to change PX schedules using adjustment bids to account for interzonal transmission constraints, while also scheduling reserves and energy balancing, taking into account intrazonal transmission constraints, in the real-time market. Where transmission rights were associated with zonal pricing designs, they were designed to be "zone-to-zone" rights that recognized fewer transmission constraints, although, one hopes, the more significant ones, as a means to promote forward trading of energy and transmission rights. A more recent experience with a decentralized market design is with the England and Wales New Electricity Trading Arrangements (NETA) market.

3) Hybrid Markets: With the failure of the California design, proposals have been forthcoming for decentralized designs that are more sophisticated. These "hybrid" designs typically assume that the real-time spot market would be cleared using locational marginal pricing. To achieve greater consistency between the decentralized forward markets and the dispatch market, these designs specify transmission rights consistent with the full network representation and they may also encourage optimization of the forward energy markets to facilitate efficient unit commitment [3], [7]. In one approach, the process of iteration toward market clearing between the system operator and the generators could be envisioned using a model of hierarchical optimization [8]–[10]. All told, these designs recognize a much greater role for the central operator in setting physical constraints on forward power trading than originally envisioned in the decentralized market concepts. Among the markets in North America, only the Electric Reliability Council of Texas (ERCOT) market currently operates somewhat in this fashion, although it seems to be gravitating toward the integrated model of the east coast ISO markets.

For our purposes here, we mainly address spot market design issues associated with the integrated market organization. However, at least some of the discussion will be applicable to hybrid designs and to other forms of market organization.

B. Outline of Paper

An effective generation market design has to balance three elements to ensure that market power is not abused while preserving incentives for efficient investment and operation [5]. These elements are spot market design, capacity market design, and market power mitigation, and the remainder of the paper is organized around them. Section II reviews the elements of efficient spot market design for energy, regulation and reserves. Section III reviews alternative approaches to pricing of generation capacity. Section IV discusses market power mitigation. Each section discusses some current research issues in the subject area; Section V highlights some additional researchable topics.

II. Spot Market Design

A. *Defining and Evaluating Efficient Spot Market Design*

Economic efficiency is the major stated reason why governments have chosen to restructure and deregulate generation markets. The political drivers, however, were revenues to the treasury from the sale of government assets, stranded cost recovery for owners of private assets, and the desire of large users to shop for power, free of obligations to pay for the historic cost of uneconomic generation assets. Economic efficiency is defined in several dimensions. Productive efficiency is the provision of a good or service through the least cost mix of inputs (e.g., capital, fuel, labor, emissions allowances). Allocative efficiency means that the good or service is consumed by those who value it most highly. Dynamic efficiency means that as market conditions change over time, production and allocation are efficient; e.g., more efficient technology substitutes for less efficient.

Standard neoclassical economic theory tells us that markets are efficient if they meet certain conditions (e.g., [11]). As applied to generation markets, if suppliers are induced to offer generation services at marginal opportunity cost, demand bids for electric power reflect the true value of power, transactions costs are not an impediment to efficient trade, and environmental and other externalities are insignificant, then the equilibrium, or market-clearing, prices and quantities are both productively and allocatively efficient. In this market model, short-term (for our purposes, spot market) efficiency can lead to longer term (dynamic) efficiency through the addition of forward markets to hedge risk and if entry and exit of generation suppliers are unrestricted. This standard model, for historical reasons of mathematical convenience, also assumed convexity of production functions and demand valuations; that is, that supply and demand could be smoothly increased or decreased over time (without "nonconvexities" such as discrete production decisions) for purposes of market clearing.

Generation markets (and almost all other product or service markets) depart from this efficient ideal for a number of reasons, the most well known of which are economic externalities due to the physical properties of power flows that cause congestion and losses, the failure of prices to reflect actual demand valuation by consumers of power due to rigid regulated rates and lack of real-time metering, the lack of competitiveness for some generation services in some locations, and the presence of economies of scale and scope in production. Left unregulated, a market beset by pervasive failures will result in inefficient quantities produced at inefficient prices and, over time, yield the wrong mix of technology at the wrong locations.

Government can attempt to correct for market failures though regulation, including oversight of market design (surveys include [3]–[5], [12], [13]).[1] When a market design fails to achieve economic efficiency, purposely or not, this is often called a *market design flaw*. However, we note that the state of knowledge is often insufficient to determine ex ante which design best achieves short- and long-term efficiency; consequently, it is only after the fact that design flaws are revealed and hopefully corrected. This is why regulatory reform is, and will continue to be, an ongoing process.

Looking back over the experience with market design, particularly in the United States but also in other countries, some designs that proved flawed over time were the result of stakeholder compromises to promote alternative design goals, while others were instead due to lack of knowledge or the state of technology. Some of these flaws will be discussed in the next section. In the United States, many of the lessons learned from flawed designs were sought to be corrected in the proposed standard market design (SMD) [14]. Although the prescriptive aspects of SMD have been withdrawn, about two thirds of the U.S. power sector has adopted or is moving toward a market design that combines the best features of SMD and eliminates the failures of the previous market designs. Table 1 shows a timeline of the introduction of bid-based markets for various generation services in the U.S. ISOs. Services appear in a column by the year that they were introduced and only reappear in subsequent columns if they were terminated or redesigned substantially.

B. *Key Spot Market Design Issues*

This section briefly reviews some of the debates over generation spot market design, primarily for energy, regulation, and operating reserves. The discussion will address design characteristics and issues associated with a typical ISO or RTO centrally optimized auction market, as found in PJM, New York, and New England. In the day-ahead market, suppliers offer generation services, buyers submit bids for energy, and the ISO procures ancillary services on behalf of buyers. These markets are then cleared through a security constrained unit commitment auction [15]. The resulting clearing prices are used for financial settlement. The real-time, or dispatch, market then prices and financially settles deviations from the day-ahead schedule, based on additional supply offers and demand bids submitted after the close of the day-ahead market.

1) Representation of Energy Offers and Bids: A generation unit's actual daily variable cost structure, depending on the technology, is composed of a number of possible components, including most notably fuel costs, which can differ for start-up, no-load, and incremental energy output; opportunity costs relative to sales outside the ISO boundary, at other

[1]We use the term regulation broadly here. Government may also fail to regulate or deregulate efficiently, but this is not our topic here.

Table 1
Bid-Based U.S. RTO and ISO Markets for Generation Services and Some Key Design Changes by Year of Introduction/Termination[(a)]

	1998-9	**2000-01**	**2002-03**	**2004-05** (as of June)
California [(b)]	DA Energy (zonal) HA Energy (zonal) RT Energy (zonal) Regulation Up Regulation Down 10 Min. Spin 10 Min. Non-Spin Replacement Reserves	*DA Energy terminated* *HA Energy terminated*	*Replacement Reserves suspended* AS based on zonal pricing	
PJM [(c)]	RT Energy (LMP) UCAP	DA Energy (LMP) Regulation	10 Min. Spin	
New England [(d)]	RT Energy AGC 10 Min. Spin 10 Min. Non-Spin 30 Min. Non-Spin ICAP OPCAP (*terminated 11/99*)	*ICAP auction terminated (ICAP requirement continued)*	DA Energy (LMP) RT Energy (LMP) AGC supplanted by Regulation *Operating Reserve markets are terminated; future introduction is under consideration*	Forward Reserves
New York	DA Energy (LMP) RT Energy (LMP) Regulation (zonal) 10 Min. Spin (zonal) 10 Min. Non-Spin (zonal) 30 Min. Non-Spin (zonal) ICAP (zonal)		ICAP Demand Curve	Regulation and Operating Reserve Demand Curves
ERCOT (Texas)	DA Energy (scheduled) RT Energy (zonal) Regulation Up Regulation Down Responsive Reserves Non-Spin Replacement Reserves	RT energy (zonal)		
Midwest ISO				DA Energy (LMP) RT Energy (LMP)

Abbreviations: AGC—Automatic Generation Control; AS—Ancillary Services; DA—Day Ahead; HA—Hour Ahead; ICAP—Installed Capacity; LMP—Locational Marginal Pricing; Non-Spin—Non-Spinning Reserves; OPCAP—Operable Capacity (a product offered in New England for a few months that was available capacity on a daily basis); RT—Real Time; Spin—Spinning Reserves; UCAP—Unforced Capacity Credit Market.

[(a)] For purposes of brevity, each column represents two years. Note that the wholesale organized markets in California started bid-based operations on March 31, 1998, PJM on April 1, 1999, ISO New England on May 1, 1999, New York ISO on November 18, 1999, ERCOT on June 1, 2001, and Midwest ISO on April 1, 2005. Unless otherwise noted in parenthesis, market based pricing for each product shown is on a system-wide basis; e.g., the market clearing energy price in the ISO New England markets prior to 2003 was for the entire system. Zonal pricing implies that the clearing price applies only to a subzone of the system. Locational pricing of reserves and capacity is usually for an aggregation of nodes and hence is better described as zonal pricing.

[(b)] The Day-Ahead and Hour-Ahead Energy Markets in California were operated by the California PX, which was terminated in January 2001, after which only the ISO markets continued to operate. The remainder of the bid-based markets are operated by the California ISO; while energy is settled in real-time, ancillary service procurement is done day-ahead, hour-ahead and in real-time.

[(c)] PJM began a zonal energy market with cost-based offers on May 1, 1997, followed by an LMP market based on cost-based offers on April 1, 1998. The bid-based LMP market began one year later.

[(d)] On March 1, 2003, ISO New England began operations under a new market design, most notably including using LMP to price energy, changing its pricing of regulation and suspending all operating reserve markets until a future date.

times, or other generation service markets; fuel storage costs (e.g., if a gas unit changes its daily storage need on short notice); and other O&M and labor costs. For an efficient dispatch, certain physical characteristics of the unit must also be considered, such as maximum and minimum operating levels, ramp rates, and minimum on and off times.

In the early phase of generation market design, a key debate was over how many spot energy offer components should be required, or even allowed for voluntary representation, especially in the forward (e.g., day-ahead or hour-ahead) markets operated by an ISO. In the early California design, the prevailing view was that day-ahead offers in the California PX should consist only of a single part: a price for the quantity of energy offered along with separate offers that contained prices for adjustments.[2] Other than total quantity, no physical generation constraints, such as ramp rates, were allowed to be specified. The motivation for the single part

[2]Generators were also allowed to submit offers to increment ("inc") or decrement ("dec") output from the cleared quantity. Such offers could then be used by the California ISO to establish a physically feasible dispatch.

offer rule was to establish a single (zonal) market clearing price without additional payments to generators for unit commitment costs, which were to be factored into the single offer price and the adjustment offers. Through these offers and the subsequent iteration between the PX and ISO, the market was supposed to result in an efficient dispatch. However, in practice, this offer rule did not result in short-term efficiency, in part because the ISO was not allowed to optimize based on unit characteristics. Another result was that when the federal regulator later determined that the California market was not competitive during the price spikes of 2000–2001, it was not possible to determine *ex post* whether a generator's output over a day was due to efficient unit commitment or an attempt to exert market power through physical withholding (as defined in Section IV-A below).

In contrast, the eastern U.S. ISO and RTO spot markets evolved from tight power pools in which generators submitted detailed marginal cost offers and physical constraints for purposes of optimized unit commitment. Consequently, in these markets the "multipart" offer eventually became standard, with a separate price component for start-up ($), no-load ($/h), and incremental energy ($/MWh).[3] There are slight variations in the offer components among the ISOs; Table 2 shows the required and optional components for the New York ISO (the other ISOs have similar offer specifications). In addition to allowing firms to better approximate their true marginal costs, the multipart offer provides a basis for introducing efficient markets for operating reserves, as discussed below. On the other hand, offers with multiple price components and physical parameters create new gaming strategies, and this has indeed been experienced in some U.S. markets, which typically impose limits on changes in each component.[4]

Also, most ISO markets allow "virtual" supply offers and demand bids in the day-ahead market. Virtual offers are single part offers (i.e., price and quantity only) that are not necessarily backed by a physical asset or real load. Any virtual supply settled financially at the day-ahead price must be "bought-back" at the real-time price (similarly, any virtual demand settled at the day-ahead price must be sold-back at the real-time price). Entities submit virtual offers and bids to arbitrage differences between the day-ahead and real-time market prices, e.g., as suppliers to sell high (day-ahead) and buy-back low (real-time). If enough virtual supply enters, this may lead to convergence of the day-ahead and real-time prices. In addition, entrance of virtual supply and the price convergence increases the volume of the day-ahead market. However, for reliability purposes, as discussed below, ISOs

[3]Wholesale buyers can also have a multipart representation of their bids. For example, an industrial customer may have an analogue to the generator start-up cost if, e.g., it is bidding in all-or-nothing fashion to shut down a particular production line on a hot day.

[4]For example, in PJM, suppliers submitted 24-h minimum run times to take advantage of opportunities to be run out of economic merit order. The ISO market monitor eventually limited such physical inflexibility. In theory, a competitive market should be incentive compatible; i.e., it should motivate generators to truthfully state their costs and physical constraints in their offers. However, in practice, the complexities of power markets may require some monitoring and mitigation of all offer components.

Table 2
Supply Offer Components in the New York ISO Short-Term Markets for Generation Services[(a)]

	Parameters	**Variability**
A. Offer Prices and Quantities		
Startup Price	$/hour	hourly
Min. Generation Energy Block and Price	MW, $/hour	hourly
Dispatchable Energy	# steps, $/MWh, MW/Step	hourly
Regulation Capacity Availability	MW	hourly
Regulation Capacity Price	$/MW	hourly
Spinning Reserve Price	$/MW	hourly, DA only
10 Minute Non-Synchronized Reserve	$/MW	hourly, DA only
30 Minute Operating Reserve	$/MW	hourly, DA only
B. Physical Generation Characteristics		
Dispatch Status	Whether ISO or self-committed	May vary
Startup Time	hours, min	May vary per commitment period, DA or RT
Minimum Run Time	hours, min	
Minimum Down Time	hours, min	
Max. Startups per Day	1-9	Static
Normal Upper Operating Limit	MW	May change over day
Emergency Upper Operating Limit	MW	May change over day
Normal Response Rate	MW/min	May vary
Regulation Response Rate	MW/min	
Emergency Response Rate	MW/min	
Reactive Power Capability	MW plotted against MVARs	Static
Physical Minimum Generation Limit	MW	Static

Abbreviations: DA—Day-ahead; RT—Real Time.

[(a)] Additional details are found in the NYISO tariff. Static refers to offer components that remain relatively constant over the life of the offer, but can be changed.

Sources: NYISO Market Services Tariff, Att. D; version Feb. 1, 2005; NYISO technical manuals.

remove accepted virtual supply offers from the day-ahead schedule prior to determining whether additional physical resources are needed prior to the dispatch market (the so-called reliability commitment). ISOs may also apply additional rules to virtual offers to limit market manipulation, such as restricting such offers to certain locations (e.g., PJM) or suspending the rights to participate of entities whose offers consistently cause prices to diverge (e.g., New England), typically as a means to garner congestion rents.

2) Spot Energy Pricing: Two primary types of energy pricing have been considered for the spot auction markets: uniform market clearing prices, in which all suppliers at the same locations are paid the same price, typically the marginal accepted offer, and "pay-as-bid" pricing, in which suppliers are paid what they offer. The efficiency implications of auction markets with these two types of pricing have been examined extensively elsewhere (e.g., [16]–[21]); here we simply note the often misunderstood fact that in a competitive pay-as-bid market, suppliers' offers will converge on their estimate of the market clearing price (i.e., suppliers will offer not at their production costs, but through an estimate of the market clearing price). This requires them consistently to raise their offers above marginal cost. Hence, if screening of offers is required for market power mitigation, it will be difficult to implement. Due to misestimates, inefficient dispatch may result.

The multipart offer creates a two-part pricing regime that combines these two pricing rules, with uniform prices that clear the market for energy, and pay-as-bid prices for the nonconvex offer components, start-up, and no-load (e.g., [22]–[27]). Start-up and no-load payments through the pool can be part of a set of energy prices and side payments to generators that supports a competitive equilibrium, in that given those prices and payments, no generator can increase its profit by deviating from the accepted supply schedule (as proven in [22]). We will discuss efficiency properties of this pricing rule further below.

3) Complementary and Substitution Properties of Energy and Short-Term Ancillary Services: Short-term generation services, such as energy, regulation and reserves, are complementary or substitute uses of the same machine. Energy and regulation are complementary services, since a unit must provide some energy to provide regulation, although the converse is not true. However, regulation and energy are also partial substitutes in that if a unit is providing regulation, it must deviate from its optimal energy output in response to regulation signals to ramp up or down. Meanwhile, regulation and operating reserves have the property of "hierarchical substitution." A quicker response reserve (sometimes called a "higher quality" reserve) can provide the same reliability benefit as any slower response reserve. When these multiple services are offered into the same regional market for electric power, the complementarities and substitutions must be fully recognized to achieve productive efficiency. For example, if an ISO is prevented from substituting higher quality reserves for those of lower quality, price "inversions" can occur in which the lower quality reserve receives a higher price, unnecessarily increasing costs.

4) Offer Representation and Pricing of Regulation and Operating Reserves: In the absence of demand-side response, regulation and operating reserves are procured by the ISO on behalf of buyers to fulfill reliability requirements (efforts to establish demand curves for reserves will be discussed below). These short-term ancillary services are either explicitly priced (i.e., with market clearing prices) or alternatively generation units are paid opportunity costs or stand-by costs based on their energy offers (possibly along with additional market payments to stimulate investment). The choice between these designs, and others, remains the subject of debate (e.g., [28]).

All offers into regulation and operating reserve markets, both those cleared sequentially or simultaneously with energy (as discussed in the next section), need to be accompanied by an energy offer that will allow the unit to be dispatched for energy as needed for reliability. The multipart bid for energy is the basis for an efficient market design for simultaneous clearing of energy, regulation, and spinning or quick start nonspinning reserves. This is because a generator whose energy output is "backed down" for the purpose of providing regulation or reserve should be paid the opportunity cost of not providing the energy (price minus its marginal energy cost, if the marginal cost of regulation or reserve is close to zero). This generally makes the generator indifferent between providing energy or these alternate services. In addition, a generator that is dispatched to a minimum operating level to provide reserves has already represented its start-up and no-load costs through the multipart energy bid and will be paid those costs if standing by to provide reserves.

While the three-part energy bid provides the right incentive for a generator to back down or stand by to provide regulation or reserves, the argument has been made that generators have other costs associated with providing these services. Hence, regulation and reserve market designs also may allow additional "availability" offer components for efficient market clearing. Table 2 illustrates the offer components in such a market, the New York ISO. These might be used to represent opportunity costs associated with selling in a different market or availability costs that are not fully captured in the multipart bid. For example, regulation offers typically allow additional bid components to cover the fixed costs of the equipment for automatic generation control as well as any additional wear and tear associated with providing regulation. Some designs allow for different offers for different regulating ranges around the generator set point. Yet others separate regulation into two services, "regulation up" and "regulation down," and allow separate offers for each. Nonspinning reserve offers can be allowed an availability component to account for the costs of standing by to provide reserve energy.

Critics of such "availability" pricing for reserves argue that in the spot markets, the marginal cost of providing reserves is negligible, and hence the availability bid will generally only be positive due to market power [28]. As such, competitive short-term reserves markets with mostly close to zero prices will fail to attract investment in reserve technology. They propose that instead of explicit spot reserve pricing, market designs are implemented that provide positive price signals for reserves, such as the scarcity pricing and forward reserve or capacity markets discussed below.

5) Sequential Versus Simultaneous Market Clearing: When spot reserves are explicitly priced through reserve offers, there are two basic ways to clear the short-term markets for energy, regulation, and reserves, reflecting the complementarities and substitutions among them: sequential and simultaneous. The sequential method first operates a market for energy followed by markets for regulation and reserves, cleared in a sequence. Variations of this approach were adopted initially in California and New England. In both cases, the different markets were initially cleared without considering substitutions with other services. This increased the potential for market power, by fragmenting what was actually a larger market when substitutions were considered and also resulted in price inversions. There are two major alternatives for introducing hierarchical substitution into sequential reserve auctions [29]. In the first, the ISO (which procures reserves for load) minimizes overall production costs, as represented by the supply bids. In this design, the ISO buys all high-quality reserves that are available to substitute for higher cost, lower quality reserves. In the second design, the ISO minimizes procurement expenditures, accounting for the prices of different reserves (the latter is also called the "rational buyer" model). That is, the ISO will make substitutions only to the extent that it lowers total procurement costs.

Sequential markets with rules for hierarchical substitution can gain some or all efficiencies resulting from substitution policies. Integrated spot markets achieve productive efficiency through simultaneous optimization (also known as joint or cooptimization) of generation services. In this design, offers for all services are submitted at the same time, and the auction minimizes as-bid production costs or total procurement cost associated with providing energy, regulation, and reserves, with the hierarchical substitutions reflected in the optimization constraints. Minimization of procurement cost is a more difficult problem than minimizing total as-bid costs, because the total payment objective is a function of both dual variables (prices) and primal variables [30].

6) Spatial Aspects of Energy and Reserves Pricing: Under either of the energy pricing rules discussed above (i.e., uniform or pay-as-bid), there are two general ways to account for the spatial price differentiation caused by transmission network effects, such as congestion and losses: zonal pricing and nodal pricing.

In theory, a zone is a set of nodes in geographical/electrical proximity whose prices are similar and are positively correlated over time; that is, they are not affected much by congestion or losses between them. Spot energy is settled at the zonal price, with side payments made for generators that are "constrained up" and "constrained down" due to congestion within the zone. Constrained up generation is that energy whose marginal cost exceeds the zonal price, but is required because of transmission constraints. They are normally paid an uplift equal to the difference between their bid and the zonal price. In contrast, constrained down generation is output whose marginal cost is less than the zonal price, but cannot be taken because of, again, transmission constraints. Constrained down generation is sometimes paid the difference between the zonal price and its bid for output that could not be accepted due to transmission congestion.

With the goal of simplicity, versions of multi- or single-zone pricing was the early choice in the PJM, England and Wales, California, ERCOT, and New England markets. This was because zonal pricing was viewed as supportive of decentralized forward markets and because intrazonal congestion, as experienced prior to the market start, was considered minimal. (An alternative view is that zonal pricing maintained the existing congestion, or "redispatch," cost subsidies from low-price locations to high-price locations.) However, when the transmission congestion within zones does not prove to be minimal, as was typically the case once centralized markets started, then the allocation of zonal redispatch costs can quickly become large and inefficient [31], [32]. For example, there is an incentive to understate one's cost and exaggerate one's potential output to magnify constrained down payments—the so-called "dec" game in California. Such difficulties have led all U.S. organized markets to either abandon or propose abandoning zonal pricing schemes in favor of locational marginal pricing. Moreover, due to its averaging, zonal pricing does not provide accurate price signals for location of new generation (or transmission or demand response) [33]. However, zonal pricing remains popular in some other countries, often because within-zone congestion is relatively unimportant in those markets.

In contrast, nodal pricing, or locational marginal pricing (LMP), provides the value or cost of the marginal energy produced or consumed at the nodes and eliminates subsidies of redispatch costs.[5] LMP is defined as the marginal cost of delivering the next increment of power at a network bus. In the absence of losses, optimization theory indicates that the number of marginal units will equal at least the number of binding transmission constraints plus one. For sellers of spot energy, the locational price is the price that they will be paid for each megawatt hour; for buyers, it is the price that they will pay for each megawatt hour. The difference between the total LMP-based payments by buyers and the total LMP-based payments to sellers is the total congestion rent collected by the transmission system operator (the total amount available to pay holders of financial transmission rights).

In the United States, operating reserves have generally been priced on a system-wide basis, although some ISOs have defined subzones for reserve procurement, with all market participants being responsible for a load-ratio share of the reserve costs. As in the case of energy, an accurate locational marginal price for reserves can provide for a more efficient dispatch, assigning costs of providing reserves more directly and providing a better signal for investment. However, a locational reserves market is not a straightforward extension of the energy market. A fully functional market design for locational reserves must achieve four objectives simultaneously: energy reserves must be priced separately from energy production at each node; sufficient generation capacity and transmission capacity must be held in reserve and priced so that no matter what contingency occurs, a feasible dispatch is possible; and the costs associated with holding capacity in reserve should be allocated by marginal costing principles to the participants whose demands imply the need for those reserves [34], [35]. This last goal is best accomplished by establishing locational marginal prices for both production and reserves at each node in the system and establishing prices for transmission elements and transmission reserves that reflect the cost of holding some production and transmission in reserve.

[5]With the exception of load LMP averaging across multiple utilities, as takes place in some regions. Load in many LMP markets has opted for a zonal price based on a load weighted average of the LMPs. When more than one retail supplier exists within a zone, this means that some cross subsidy takes place.

7) Revenue Sufficiency Guarantee: All the U.S. energy and reserves markets with multipart supply offers (start-up, no-load, energy) and simultaneously optimized energy and reserve markets have converged on another crucial market rule: the guarantee of offer revenue sufficiency. This rule states that for all generation service offers by a particular unit that are accepted in the spot auction, the total daily revenue from the market must at least equal the offer requirements. If not, the supplier is eligible for a "make-whole" payment that is recovered as an uplift charge to all load.[6] The payment guarantee further reduces the uncertainty associated with a bundled offer (e.g., a one-part offer) and allows for an efficient dispatch with no generator able to increase its profits by deviating from the accepted supply schedule. This is an important property, because otherwise generators will be tempted to deviate from their schedules, which can cause reliability problems in real time, as has been experienced in California.

8) Scarcity Pricing and Demand Curves for Reserves: In order to promote allocative efficiency and investment in capacity, prices should rise above marginal cost if generation capacity is binding—i.e., the requirements for reserves and energy exceed what generation can provide [36]. In electricity markets, then, reserve shortages are the "real-time" indicators of such market "scarcity" and hence when competitive market prices should be getting high. There are two major barriers to connecting short-term reliability and market scarcity. First, very little of the system load is currently price responsive in the short run. In the United States, this is mainly because most retail customers see prices averaged over a month or more. Their consumption decisions would be unaffected by price spikes in the wholesale market, unless they are responding to public service announcements or they are among the minority that participate in utility interruptible rate or load control programs. Consequently, during peak periods consumers pay far less for power than it costs to generate. Second, because reserves are modeled as 'hard' constraints, the system is declared to be reliable if the required amount of reserves is present. Anything less is declared unreliable. Any additional reserves are not paid for. This approach was satisfactory from a purely reliability perspective under monopoly regulation, but neither of these assumptions provides appropriate market incentives. Reserves should be allowed to be shorted at a price, so long as security is not violated; also, some degree of excess reserves should be priced because reliability increases as more reserves become available.

The method for substituting for the lack of buyer price responsiveness is so-called scarcity pricing. There are several ways to implement scarcity pricing. One is the now-abandoned England and Wales method of adding to the price a factor equal to the product of the loss of load probability on a given day and an assumed value of unserved energy. Another, which addresses directly the reserves pricing issue, is to employ a demand curve for reserves, ideally based on the expected value of lost load as reserves diminish, that will increase the price the ISO pays if reserves are short and also pay a low but positive price for reserves above the hard requirement [5]. A high price for operating reserves will then translate into a high cost of energy, as generators factor in the opportunity cost of the high reserves price in their energy bids or through the cooptimization algorithm.

This artificial, but market-based, demand curve has two purposes. It sends high price signals during periods of scarcity to expand supply and restrict demand. Further, it eliminates the artificial all-or-nothing construct of reserves, recognizing that more reserves are worth something. This curve should be calibrated to promote demand-side bids that can eventually substitute for it (e.g., if the artificial shortage price hits \$1200/MWh, buyers that value power at less than that price will be prompted to bid and voluntarily reduce consumption). In theory, a competitive market in which shortage prices reflect the value to load of reliability can result in the optimal incentives for investing in new capacity [37]. However, the presence of price caps or other market power mitigation measures may mean that new generators cannot earn enough gross margin (revenue minus variable costs) to cover fixed costs. This endangers the reliability of the system and shows that the design of spot markets should not be done separately from the design of market power mitigation and capacity markets, as will be discussed in the following sections.

9) Sequence of Forward and Spot Generation Markets: In the most general sense, the ISO markets for generation services should be a sequence with the following properties. For each forward market, the financial position taken by each buyer and seller can be changed in the next market by buying back or selling back the prior position. A financial position can be turned into a physical position by acquiring new capacity. In the transition to the final, physical, or dispatch, market, the last adjustment is made and the prices associated with delivery of the actual product are cleared. In electricity market design, this is often called a multisettlement system.

In the actual U.S. markets, there are several auxiliary procedures and rules that have arisen to substitute for the lack of demand responsiveness and for situations where prices in the sequence of markets are insufficient to ensure market clearing (e.g., when excess capacity is available but offered supply before the dispatch hour or actual output is not sufficient to meet actual demand). First, most markets have added a type of reserve purchase that reflects the difference between the ISO's next-day forecast and the bid in next-day load. This additional reserve is typically cleared by paying "as bid" for start-up and no-load for any generators postured to provide the reserve over and above the day-ahead market clearing level. Second, several markets have instituted financial penalties for deviations from the market and ISO's dispatch instructions; that is, for any generator that does not perform as instructed based on its accepted supply offer.

[6]For example, consider a generator with a \$3000 start-up cost and a \$40/MWh energy offer for its range of output, which is run for 4 h, during which it gets paid a \$50/MWh price for output of 20 MWh/h. It thus gets paid $\$50/\text{MWh} \times 20\ \text{MWh/h} \times 4\ \text{h} = \$4000$. According to its offer, it needs at least $\$3000 + (\$40/\text{MWh} \times 20\ \text{MWh/h} \times 4\ \text{h}) = \$6200$ to cover operating expenses for that output. Hence, the generator is eligible for a revenue sufficiency payment of \$2200.

III. Market Design for Generation Investment

A. *Is a Market for Generation Capacity Needed?*

In normal commodity markets, funding for the capacity and storage required to meet peak demands is provided by higher than normal prices during those times. But in several U.S. power markets, there are separate capacity markets for electricity or other resource adequacy mechanisms to ensure that "enough" generation capacity is built.[7] Outside the United States, commentators are concerned that markets without such mechanisms will fail (e.g., [38]).

Several reasons are offered for the prevalence of such capacity or resource adequacy mechanisms, all pointing to unique characteristics of power markets or one failure or another of such markets to conform to the assumptions of the perfect competition ideal [39], [40]. One is the combination of capital intensiveness and absence of storage; as a result, meeting peak demands that only occur a few hours per year is very expensive. Spot prices in the thousands of dollars may be needed for recovery of capital costs, depending on the type of unit and hours run. In contrast, other industries that are less capital intensive have more ability to store and transfer commodities from one period to another. They can also charge high prices to dampen demand during peak periods. As a result, the swing of marginal cost from off-peak to peak periods is not nearly as extreme as in the power industry.

But high peak marginal costs do not by themselves explain the need for capacity markets. The other consideration is inefficiencies in the demand-side of the market. One failure of the demand-side is the presence of regulatory price caps, typically justified on the basis of market power mitigation, or other sources of price rigidity that prevent prices from climbing anywhere near that high during peak periods.

A further demand-side failure noted above is that price fluctuations in the bulk power market are not communicated to most retail customers, who pay a rate that is either constant or just seasonally adjusted (possibly under regulated retail rate caps). In contrast, when consumers are subject to prices that fluctuate in real time, they do respond by decreasing loads in peak periods or shifting uses to off-peak periods [41]. This lessens the need for expensive capacity. In theory, real-time prices faced by all market participants will result in the optimal amount of system capacity and reliability, as the market prices will express the consumers' willingness to pay for power during peak times—just as in other commodity markets. This was, of course, the original vision of Schweppe *et al.* (e.g., [36]) for a power market in which decisions are coordinated by price. But price regulation and lack of hourly meters for most customers mean that this goal is unattainable, at least in the near future.

As a result of these demand-side failures, generation capacity becomes a public good. That is, the benefits of adding capacity are received by all consumers in the market to whom its power can be delivered and are not captured by the owner of the capacity in the form of higher revenues. Economic theory says that public goods tend to be undersupplied in markets, so therefore too little capacity would likely be built in the face of the demand-side failures.

Besides the demand-side market shortcomings, another market problem provides a rationale for capacity markets: that of market power. In the extreme, unresponsive demand means that pivotal suppliers can raise prices at will. Even if no individual supplier is pivotal, prices can be above marginal cost. However, this will be less of a problem if there is more generation capacity, particularly in spot markets if loads forward contract the bulk of their needs. If the output of most capacity is already committed to be sold at a fixed price, there is little advantage to manipulating spot prices [43].

B. *Alternative Market Designs for Adequate Capacity*

Several types of fixes are proposed to correct the market failures and ensure adequate generation capacity.

1) Energy-Only Market With No or High Price Caps; No Capacity Requirement: The first approach is to forgo capacity requirements and to rely on scarcity pricing of energy or operating reserves to provide enough gross margin to generators. This is the course taken by the Australian and some European systems (although there may be resource adequacy requirements at the retail level).

2) Long-Term Contracts or Options for Energy: A second approach is a regulatory requirement that those who sell power to consumers hold long-term contracts or options for energy, perhaps with a stipulation that the options be backed up by physical generation assets [44], [45]. This is the proposal made in 2003 by the Public Utility Commission of California [46]. Another version of such a design is the forward reserve market implemented in New England [28]. Such a requirement could be complemented by a control system (and political will) that in the event of a shortage would first curtail consumers who lacked such contracts; this would correct the demand-side market failure by converting the public good of capacity into a private good that consumers would be willing to buy and generators would be paid for.

3) Payment Mechanisms for Capacity: A third type is payment-based mechanisms, where the system operator provides a fixed or variable payment per megawatt for capacity, subject perhaps to performance penalties. The payments can take two forms. The first is a payment for installed capacity separate from payments for energy, as was done in Argentina until March 2000. In Spain, the capacity payments are similar to stranded investment compensation [45]. The second form of capacity payment is an uplift in the energy payment that

[7]Capacity requirements are typically distinguished from operating reserve requirements in several ways. First, the former is typically a multiple of a load-serving entities' peak load, whereas the latter is a fraction of peak load or a load-ratio share of the largest contingency (multiple contingencies). Second, the set of generators that can fulfill capacity requirements is different from those that can fulfill operating reserve requirements of various time frames. Hence, some generators may be eligible for capacity payments that are not competitive in operating reserves. For these and other reasons, the addition of a capacity market will produce a different revenue stream for generators than the operating reserve markets.

depends on the state of the system and the capacity availability, as in the aforementioned LOLP-based payment in England and Wales before March 2001.

4) Quantity Requirements for Capacity: A fourth approach is quantity-based methods, in which either a market operator procures reserve capacity directly, as Sweden has, or sets up a capacity market.[8] There are several flavors of capacity markets, but each has the following basic features: a target level of system generating reserves (commonly based on a probabilistic adequacy criterion of capacity deficits occurring only once every decade); the allocation of responsibility for meeting that target by creating an obligation (either on the part of load serving entities (LSEs) or the system operator itself) to acquire capacity or capacity credits; a system to assign credits to generators, based on their capacity and reliability, and perhaps to demand-side programs such as load controls that can substitute for capacity; a system that allows trading of credits so that those with credits beyond their needs can sell them to those who are short; a set of requirements defining how far ahead of time (days, months, or years) those responsible for obtaining capacity must contract for it; and a system of incentives to encourage availability of capacity when needed and for penalizing LSEs who have insufficient credits. Quantity-based systems include the installed capacity (ICAP) markets of the northeastern U.S. ISOs, in which the traded commodity represents "iron in the ground"; available capacity (ACAP) markets, in which capacity is given credit on a day-by-day basis only if it is available on that day; and scarcity pricing of operating reserves, discussed earlier, in which the system operator states a maximum willingness to pay if it is short of spinning or nonspinning reserves. In the latter case, if the maximum willingness to pay is sufficiently high, then generators will receive enough extra revenues to pay for its capital costs from either the operating reserves or energy markets when reserves are short. High operating reserves prices spill over to the energy market during shortage periods because most generators can choose to sell in either market, and so there will be an opportunity cost to selling in the energy market.

We turn briefly to examine the ICAP market model in more detail, because it is an important feature of several U.S. markets that evolved from cost-based power pools. The system of ICAP requirements uses market incentives to implement the chosen installed reserve margin, so that the reserve capacity is acquired at the lowest cost. The primary market incentive consists of the fact that rights to ICAP resources are tradable. Thus the provision of ICAP resources to loads occurs within a competitive market. In the U.S. markets, most ICAP credits are either self-provided by vertically integrated utilities serving their own load or bilaterally contracted; a small percentage is traded through the centralized ICAP auctions. In states with retail competition, a daily ICAP auction is desirable to allow for daily adjustments of competitive suppliers. An important characteristic of ICAP systems is that these resources do not necessarily have to be available or on-line at particular times, such as the system peak; rather, they are physically available and in operable condition for most of the year. The fact that they may not necessarily be available at moments of supply scarcity is one of the key weaknesses of ICAPs. The market need is for an instrument that is more forward looking that can be used to finance construction in the year to several year-ahead horizon.

5) Demand Curves for Capacity: A fifth approach is a hybrid of the price-based and quantity-based approaches. It involves the market operator creating a downward sloping demand curve that pays more for capacity if reserves are short and provides some payment even when there is significantly more capacity than the amount needed to attain a given reliability standard. The motivation for using a demand curve is that capacity prices will be less volatile, providing a more predictable stream of revenues for generators that they "can take to the bank." In contrast, a pure ICAP system will, in theory, bounce between two extremes, depending on whether there is too little capacity or too much relative to the target. The upper extreme is the penalty that LSEs pay if they have insufficient credits, while the lower extreme is zero. Use of such a demand curve may also help moderate market power, since a pivotal supplier would no longer be able to force the ICAP price up to its effective ceiling simply by withholding just enough capacity so that the market has fewer credits than the target reserve margin requires. A variant of the fifth approach is the operating reserves markets we described earlier, in which a market operator has a downward demand curve for reserves [5].

There is currently no consensus as to which approach to capacity market design among those tried or proposed (including none) is best. New design elements are being devised at this writing to address perceived shortcomings of existing approaches. For instance, the New York ISO has a locational ICAP system, so that capacity in different locations represents separate commodities and has separate prices. Meanwhile, the New England ISO is proposing a sophisticated set of penalties to address the criticism that ICAP payments reward "iron in the ground" and not performance during times that capacity is truly needed. To encourage those who receive ICAP payments to increase their availability, New England proposes reducing ICAP payments in each time period by the proportion of time that a generating unit is unavailable when energy prices exceed a certain threshold [48]. Finally, PJM has considered differentiating capacity in another way, according to its flexibility. The argument is that capacity with quick start times or fast ramp rates is more valuable to the system than inflexible capacity,

[8]As each large electricity consumer or company that serves end use consumers must contract sufficient capacity resources to meet his peak demand plus a reserve margin, the sum of all generating capacity should exceed total peak demand by the same reserve margin. This margin is calculated by the regulator or ISO to obtain a certain level of reliability. For instance, an "over–under" analysis [47] might be undertaken to determine what level of reserves yields the minimum sum of capital, operating, and outage costs, based on an assumed value of lost load. A regulator might specify that the reserve margin achieving the minimum cost be chosen. But since the relationship of capacity additions and expected outage costs is asymmetric, this suggests that in the presence of uncertain load growth, it is better to have too much capacity than to have too little. The market power problems accompanying low reserve margins only reinforces that point. Hence, the best reserve margin might be somewhat to the right of minimum.

and should be rewarded. The reason why the energy market might not yield the right amount of flexible capacity is price caps, which mean that the ability of a generator to quickly respond to a price spike will not be as rewarded as it would be in an uncapped market. A counterargument is that appropriately designed ancillary services markets would be as or more efficient a means to reward flexibility, while some (e.g., the apparent majority of participants in the Australian market) say that removal of energy market price caps is the right response to this need.

IV. Market Power Monitoring and Mitigation

Market power is the ability of a profit-maximizing seller or cost-minimizing buyer to alter the market price—that is, to raise it or lower it from the competitive level. Through analysis of the market and repeated interaction with other sellers and buyers, market participants learn how much market power they have and attempt to increase their profits accordingly. We have discussed market power as an issue in generation market design several times in passing, first as one reason why otherwise well-designed short-term markets can yield inefficient (or inequitable) outcomes, and then as a reason why capacity markets are sometimes used (in concert with market power mitigation) so that the market does not have to rely on high energy prices to elicit investment in generation. While market power is a matter of degree, and is difficult to quantify accurately, all governments have laws and regulations (or the ability otherwise) to limit the exercise of market power in the electricity sector, for purposes of improving efficiency and equity and also for addressing the interests of political constituencies. In this section, we will discuss the sources of market power, methods of mitigation in the United States, and design requirements for optimal market power mitigation.

A. *The Sources of Market Power in Generation Markets*

Suppliers in generation markets attempt to exercise market power either by reducing the physical availability or output of a generator (from its true operable capability) or by changing its offer price from its marginal cost such that it produces less (or more) than it would otherwise. In U.S. regulatory parlance, the former is sometimes called "physical withholding," while the latter is called "economic withholding." In a market with fewer suppliers, or in which there are very large firms, the greater is the capability to withhold profitably. Further, transmission congestion creates bottlenecks that magnify market power in certain locations (and at least some generation was built in part to provide transmission support and thus "must run" for the sake of reliability). Suppliers may actively congest or decongest transmission constraints to enhance their locational market power in energy (i.e., collect congestion rents) and to affect revenues from transmission rights [49].

In addition to market concentration, market power in electricity is greatly exacerbated by the lack of storability of electric power and the requirement of second-by-second balancing. As noted, short-term demand for electricity is largely inelastic and, at least in the U.S., there are regulatory barriers to increasing price responsiveness. Hence, when there is market scarcity, and all suppliers are needed to make available or run most or all of their units to meet demand, then the ability to exercise market power becomes more acute.

B. *Optimal Mitigation of Market Power*

The regulatory approach to market power monitoring and mitigation is somewhat different in each country, reflecting the prevailing law and regulation, historical evolution of the industry, and other factors. For example, in the Australian national market, which is an energy-only wholesale market, suppliers are subject to a AUS $10 000/MWh price cap until a cumulative price threshold is reached, after which the offer cap becomes much more restrictive.[9] In contrast, as shown in Table 3, the U.S. ISO markets are typically subject to lower offer caps. This then requires that market design provide revenues that would otherwise be obtained at a competitive market price during shortages (or at other times), such as through administrative scarcity pricing (of energy and reserves) or capacity markets. A market power mitigation regime that results in both short-term and long-term economic efficiency could be termed "optimal" and has its foundation in the efficient market designs that we discussed in Section III.

The U.S. federal regulator has established the following four-level approach to market power mitigation [50]:

1) Long-Term Ex Ante Screening for Market-Based Rates Authorization: Prior to allowing suppliers to sell at market prices, the regulator requires a market concentration analysis of the supplier's destination markets under various market conditions, using various market metrics (percentage market share, sum of squared market shares, or pivotal supplier determination), to infer whether its pricing will be sufficiently competitive. If the supplier fails these screens and cannot take steps to mitigate its market power (e.g., by joining an ISO market and being subject to its mitigation), its application is denied and its wholesale energy must be sold at cost-based rates [51].

2) Oversight of Forward Markets: Following the California and western U.S. price spikes of 2000–2001, suppliers are subjected to new behavioral restrictions in the forward markets, such as not violating market rules and not misrepresenting fuel or contract prices [52].

3) Ex Ante Mitigation of ISO Spot Markets: In the ISO markets, offers of generation services into the spot markets are subject to a "safety net" offer cap that sets an upper bound on offer prices. In addition, more restrictive screening of offer prices may take place under various market conditions. If the offers fail the screening, they are mitigated, either to a market-based reference offer (e.g., New York, New England, Midwest ISO) or a marginal cost offer (PJM). Most ISO markets have a trigger for such screening, such as a market price above some level. In general, the market operators then use a

[9] Specifically, the market's "cumulative price threshold" is reached if the sum of market prices reaches $150 000 in any seven-day period. At that point, the market operator imposes an administered price cap of $100/MWh between 7 A.M. and 11 P.M. on business days and $50/MWh otherwise.

Table 3
Rules for Screening and Mitigating Offers Into U.S. ISO Energy Markets

	Safety Net Offer Cap	Rules inside load pockets	Rules outside load pockets			
		Offer caps	Triggering condition for offer screening	Offer conduct test	Market price impact test	Offer Mitigation
New York	$1000/MWh	RP + 8760 × average price in RTM over prior 12 months × (2% ÷ total constrained hours over prior 12 months)	LMPs > = $150/MWh; All suppliers	Lower of 300% increase or an increase of $100/MWh over RP	LMP increases by 200% or $100/MWh	Market RP
New England	$1000/MWh	Net Annual Fixed Cost/ Expected Run Hours	Supplier is pivotal	Lower of 50% increase or an increase of $25/MWh over RP	LMP increases by 200% or $100/MWh	Market RP
Midwest	$1000/MWh	Net annual fixed cost of a new peaker ÷ total constrained hours over prior 12 months	Binding transmission constraint and suppliers with threshold generator shift factor on that constraint	Lower of 300% increase or an increase of $100/MWh over RP	LMP increases by 200% or $100/MWh	Market RP
California	$250/MWh	Currently managed through RMR contracts; lower of $50/MWh or 200 % greater than the MCP	MCP must be >= $91.87/MWh	Lower of 200% increase or an increase of $100/MWh over RP	Lower of a $50/MWh or 200% increase in the MCP compared with a reference MCP in which all bids failing the conduct test are replaced.	Market RP
PJM	$1000/MWh	OOM generators capped at marginal cost plus 10%	No mitigation of in-merit generation; OOM generators capped at marginal cost plus 10%; i.e., cost-based RP			

Abbreviations: Out-of-merit (OOM); Market clearing price (MCP); Reference price (RP). This table is based on a similar one in [50].

"conduct test" in which spot offers above reference prices by some preset threshold (in either percentage terms or absolute dollar terms) are flagged for evaluation, followed by a "market impact test" in which it is determined whether offers that failed the conduct test actually had an impact on the market price, typically also by a preset threshold. If yes, the offer is mitigated and the market price is then recalculated and finalized. Table 3 shows these rules for the various ISO markets. Suppliers must typically offer all their residual available capacity into the real-time market (i.e., no physical withholding).

For example, in PJM, any spot supplier that has its output adjusted to resolve a transmission constraint has its spot offer capped at marginal cost (as submitted to the ISO by the generator owner), but is eligible to get paid the locational marginal price. Any transmission unconstrained generator is subject only to an energy offer cap of $1000/MWh. In general, all U.S. ISO markets have tighter offer limits inside than outside load pockets. Imports may be subject to different screens and mitigation. For example, although imports are typically subject to the safety net offer cap, they may not be subject to other screening rules applicable to generators within the ISO boundaries.

4) Ex Post Refunds and Settlements: If one or more of the prior methods of market power screening and mitigation fails, and the regulator determines that tariff conditions were violated, then the offers submitted by firms that exercised market power could be reexamined and prices recalculated as a basis for refunds. The major recent example of this was the refund proceedings for the California and western markets in 2000–2001.

Each of these methods involves regulatory determination of the appropriate level of market shares, market offers, market prices, or other types of market behavior to reduce the potential for the exercise of market power. As such, regulatory errors are likely: either overmitigating in some cases, driving the price paid to suppliers below long-run competitive levels, or undermitigating, and allowing some generators to make profits well above competitive levels. Particular difficulties are presented when estimating a competitive benchmark price by factors such as recovery of unit commitment costs, intertemporal constraints (e.g., due to emissions restrictions and energy (fuel) limitations), and the economies of scale in generation investment mentioned above [53]. The focus of U.S. market power regulation in recent years has been to try to reduce such errors by reducing market uncertainty about mitigation rules (e.g., clarifying what types of market behavior are allowed and making spot market screening more transparent and *ex ante*) and through modification of market design. Regulators must also be cognizant of the offer incentives created by mitigation rules. For example, when market-based reference prices are used as a benchmark for allowable ISO energy market offer price increases, the supplier may seek to increase the reference price over time to create more latitude for affecting market prices within the rules. Strict offer caps (e.g., $1000/MWh) also become "focal points" for offer prices in repeated auctions, i.e., prices to which suppliers converge over time under certain conditions (e.g., reserve shortage) because they have greater confidence that other suppliers will also offer at around that price.

In many ISO markets, where optimal market power mitigation can be developed in close relationship to market design, the current focus is on improving locational market power mitigation, because the presence of transmission constraints makes it difficult not to make regulatory errors for specific generating units. The more restrictive the mitigation, the harder it is, all other things equal, to attract investment to locations where the spot price is suppressed. The market design solution that is appropriate to ensure fair generator revenue recovery and promote entry—administrative scarcity pricing, locational reserve or capacity pricing, forward reserves, entry/exit auctions, and so on—has varied from region to region. Indeed, different market design solutions could lead to similar results. Hence, there is currently a proliferation of design schemes to address the market impact of locational market power mitigation and provide long-term generator revenue sufficiency.

There are other methods to reduce market power: forced divestiture of generation assets, increased regulated investment in transmission to relieve constraints and thus increase the scope of the generation market, and subsidized investments in demand response. Depending on the country or region, some of these methods may be available to the regulator as it seeks to reduce market intervention while guiding the market toward competitiveness and efficiency. Each has its advantages and limitations. For example, changing the structure of the market to reduce concentration will certainly result in less need for regulatory controls. However, divestiture may not work appropriately the first time and may need to be repeated, as was the case in the England and Wales market. Moreover, divestiture can diminish some benefits of economies of scale and scope. Similarly, if the regulator provides incentives for increases in regulated transmission investments, this may create uncertainty among generation investors, given that spot prices are often affected by transmission constraints.

V. Research Agenda

Each of the topics that we have covered remains a rich area for research. Design improvements are constantly sought in the competitive generation markets now in operation around the world. Software engineers are kept busy attempting to implement the designs. A number of issues that need additional research have already been mentioned, such as locational pricing of reserves, demand curves during scarcity, and analyzing alternative capacity or forward reserve market designs. In this section, we will note interesting applications of analytical methods and a few additional substantive topics.

Market designs for spot markets and capacity markets, as well as detection of market power in those markets, can be tested with models, including equilibrium models (e.g., [54]), more sophisticated dynamic models [55], [56], and agent-based techniques. For example, [54] calculated the equilibrium values of the ICAP price in PJM as well as probabilities of alternative energy price regimes, and base and peak load generating capacities under each regime.[10] Market modeling incorporating transmission constraints has allowed for more detailed consideration of locational market power [57]–[62]. Laboratory experiments with live subjects, although expensive, allow for exploration of market design subtleties that models often omit. Finally, empirical comparisons of existing systems provide irreplaceable evidence of how designs work in practice, although the lack of experimental controls often implies that there are several possible explanations for market outcomes (e.g., [53], [61]). These sorts of investigations are needed for the fuller range of market design proposals that are now being considered. Anticipating and preventing market design problems is likely to be cheaper than correcting them after the fact, as California has learned.

We suggest two further topics for investigation in spot markets: pricing of nonconvex generation markets and pricing of reactive power. We turn first to examine the implications of pricing nonconvexities in energy markets (and in markets generally). In the context of a market with "lumpy" cost functions and technology—the example of lumpiness in costs discussed earlier is the fixed start-up cost associated with production of energy, while lumpiness in technology in this context means that additional capacity comes in discrete or indivisible amounts—it has been shown that the short-run dispatch can be inefficient if offers are not permitted to reflect the lumpy components and that a market equilibrium may not be achieved in energy prices alone [13], [22]–[27]. This provides theoretical support for the two-part pricing regime for spot energy described above. However, investment incentives may be distorted in lumpy markets with nonprice responsive (inelastic) demand, although increased demand response or scarcity pricing may improve this outcome [27].

The other topic of current interest is pricing of reactive power [62]. Many systems are dispatched without using a full ac optimal power flow, while imposing overly restricted voltage levels. As a result, the market is incomplete: the essential commodity of reactive power is either inappropriately priced or not priced at all. A basic question is whether it would be more cost-effective for an ISO to sign long-term contracts for reactive power (similar to "reliability must run" contracts for expensive generation in load pockets) or to operate forward and spot markets for reactive power [63], [64]. If full markets are to be created for reactive power, work is needed to improve optimal power flow software and its integration with unit commitment models.

VI. Conclusion

The design of efficient generation spot markets has been an evolutionary process in most countries. While many design experiments have been run, and some have failed, there is increasing understanding of the relationship between design elements.

As stressed in this paper and by previous authors, the various components of spot market design for energy and ancillary services, the decision as to whether to include a capacity market and the design of that market, and the approach to market power mitigation are policy choices that

[10]The analysis in [53] found that the equilibrium ICAP price is 64 000 \$/MW/yr, although other researchers would suggest lower or higher values. Each generator's expected revenue was divided between energy and ICAP sales; ICAP accounted for 40% of the gross margin (revenue minus operating expenses) for a baseload unit and 97% for a peaking plant. Under assumptions that entry occurs until profits are zero, each plant's gross margin precisely equaled its levelized capital cost.

must be made in concert and then finely tuned to ensure that efficient pricing and efficient investment both result. Some of the topics discussed, such as which capacity incentives are most efficient, remain open questions.

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