Free markets. Real solutions.

R STREET'S ELECTRICITY 101 SERIES
NO. 1

August 2016

FEDERAL POWER ACT AND ORGANIZED ELECTRICITY MARKETS

INTRODUCTION

Organized electricity markets that allow competition have evolved considerably since their inception in the late 1990s. A host of policy, market and technological developments have altered their outcomes and performance. Such changes make it both timely and important to review the structure and performance of these markets in an evolving policy and economic environment.

In its June 10, 2016 letter to Federal Energy Regulatory Commission (FERC) Chairman Norman Bay about the state of organized, competitive electricity markets, the House Energy and Commerce Committee asked whether such markets are equipped to adapt to technological advances, new market forces, shifts in consumer expectations and changes in the regulatory and policy landscape. The committee noted these shifts could result in litigation over the distinction between federal (wholesale) and state (retail) jurisdiction, citing two recent court decisions over the reach of the Federal Power Act. This marked the beginning of the committee's long-term review of electricity markets and the suitability of the Federal Power Act in an evolving electricity sector.

THE ROAD TO ELECTRICITY COMPETITION

Energy regulation began at the state and local levels in the late 19th century. Local authorities granted private companies monopoly franchises in exchange for regulating their rates and services. These regulated monopoly utilities owned all aspects of electricity production, transfer and delivery (generation, transmission and distribution). State legislatures later pre-empted local regulation by creating state public utility commissions (PUCs) to regulate rates based on the cost to serve customers.

In 1920, Congress established the Federal Power Commission (FPC) through what is now known as the Federal Power Act (FPA). The law was intended to better coordinate hydroelectric development by granting the FPC authority to establish hydroelectric projects, which previously fell to the states. With this exception, most energy resources remained regulated at the state and local levels until the New Deal era.

The New Deal marked the beginning of contemporary federal energy regulation. The FPA amendments of 1935 established a bipartisan five-member commission to run the FPC as an independent regulatory agency. It also gave the commission authority to regulate wholesale (sales for resale) electric-utility rates in interstate commerce, as well as oversight of utilities' interconnections that increasingly tied transmission systems together across state boundaries. Interconnection enabled utilities to sell power to other utilities bilaterally, at rates determined by the FPC on a cost-of-service basis.

In 1977, the FPC was renamed the Federal Energy Regulatory Commission (FERC) and placed within the newly created Department of Energy.[1] Congress took the first step toward electricity competition by passing the Public Utility Regulatory Policy Act (PURPA) of 1978. The law helped create a market for some forms of non-utility electricity producers by requiring utilities to buy power from lower-cost independent producers. This also gave rise to the broader concept of generation independent of regulated monopolies. Sometimes inaptly described as "deregulation," this "restructuring" allowed generators and transmission owners to compete in an open wholesale marketplace. Restructuring limited the monopoly-utility model to distribution services, leaving customers to choose their electricity supplier. It also fostered a competitive market to determine wholesale rates in lieu of cost-of-service regulation.

About half the states initiated restructuring in the 1990s; Texas, Illinois, Ohio and most mid-Atlantic and Northeast states retained it. While the decision to restructure rests with states, it calls for reliance on competitive wholesale markets under FERC authority.[2] Competition requires generators to have open access to the transmission system, but regulated utilities initially could restrict other entities from using their transmission lines. The Energy Policy Act of 1992 amended the FPA to give FERC authority to grant transmission access on request. In 1996, FERC issued the "open access" rule (Order No. 888), which required transmission owners to provide nondiscriminatory transmission access. This encouraged the development of centrally organized electricity markets, where independent system operators (ISOs) would operate the transmission system to facilitate open-access competition.

ORGANIZED WHOLESALE MARKETS

In 1999, FERC issued Order No. 2000, which encouraged utilities to join an ISO or regional transmission organization (RTO).[3] RTO/ISOs are independent, nonprofit organizations responsible for wholesale grid reliability and transmission planning and operation. States and industry participants have voluntarily formed seven jurisdictional RTO/ISOs, six of which are FERC-jurisdictional.[4] All restructured states joined an RTO/ISO, as did many regulated-monopoly utilities. Today, RTO/ISOs manage more than two-thirds of the nation's electricity volume and they continue to expand.

RTO/ISOs use centrally operated, "organized" spot markets to balance supply and demand in real time.[5] They also send long-term price signals to balance the supply and demand of generation and transmission-infrastructure investment. Some RTO/ISOs use capacity markets to "patch up" deficiencies in the spot markets, which would ensure adequate resources exist to meet infrastructure-planning needs." Markets enable grid operations and infrastructure investment to respond nimbly to changes in market fundamentals, such as declining natural-gas prices or shifts in electricity demand.

RTO/ISO markets are technology-neutral and designed to select supply and demand resources that provide grid reliability at the lowest cost. This has sometimes led to the selection of politically unpopular resources, especially in restructured states, where markets have replaced state-approval processes as the means to decide infrastructure investment. Federal and state policymakers have enacted a variety of subsidies and mandates for politically preferred technologies in ways that often conflict with the efficient and reliable functioning of organized markets.

State-imposed decisions to build new power plants or retain unprofitable plants can distort organized markets. Some of these have led to jurisdictional disputes. For example, the U.S. Supreme Court's April 2016 ruling in *Hughes v. Talen Energy Marketing LLC* found the Federal Power Act pre-empted a Maryland subsidy for a new power plant that intruded on FERC's authority over interstate wholesale rates.

The performance of organized electricity markets depends on the quality of their design. The physical challenges of maintaining electric supply-demand balance necessitate complex market mechanisms that require FERC approval. Initial market designs and rules were scripted around prevailing technologies, which has required adjustments as those technologies evolve. Proposed changes typically come from FERC, the RTO/ISOs, individual RTO/ISO stakeholders or independent market monitors.[6]

Numerous market-rule changes implemented this decade have aimed to improve the efficiency and reliability of the organized markets. Some of these come through one-size-fits-all FERC rulemakings, such as compensation for demand-response resources.[7] Many occur on an RTO/ISO-specific basis to account for regional differences. For example, RTO/ISOs have pursued differing market-design approaches to integrate variable renewable resources, which depends in part on the expected market penetration of wind and solar generation in each region. The increase in distributed-energy resources (DERs) presents unique operational and market-integration challenges for RTO/ISOs. The reliable and efficient integration of DERs in organized markets will require cooperative federalism, as FERC and the states have jurisdiction over different aspects of DERs.

ISSUES

The following issues may be examined in the House Energy and Commerce Committee's review of the state of organized electricity markets:

- The performance of organized electricity markets as gauged by market efficiency and reliability;
- How non-FERC jurisdictional federal and state actions affect the performance of organized markets;
- The ability of organized markets to promote innovation and efficiently adapt to new technologies, market forces, policies and shifts in consumer expectations; and,
- Whether the Federal Power Act is well-suited for the electricity system of the future.

CONTACT

The R Street Institute will provide further educational materials and perspective pieces on issues raised by the committee. If you have questions regarding these subjects, please contact Electricity Policy Manager Devin Hartman or Outreach Director Lori Sanders at the R Street Institute at 202-525-5717.

ENDNOTES

1. This was the result of the Department of Energy Organization Act of 1977.

2. The exceptions to FERC wholesale-market authority are Hawaii, Alaska and most of Texas, whose transmission systems are not connected with other states.

3. RTOs perform the same core functions as an ISO.

4. These include the California ISO (CAISO); the Southwest Power Pool (SPP); the Midcontinent ISO (MISO); New York ISO (NYISO); New England ISO (ISO-NE); and the PJM Interconnection (PJM). The Electric Reliability Council of Texas (ERCOT) is not FERC jurisdictional.

5. These are known as energy and ancillary service markets.

6. RTO/ISOs are membership-based organizations. FERC usually prefers RTO/ISO stakeholder processes to develop market-rule changes.

7. This refers to Order 745, which standardized energy-market compensation for demand-response (DR) resources. DR is the reduction in electricity usage by customers from their normal consumption patterns.

Free markets. Real solutions.

R STREET'S ELECTRICITY 101 SERIES
NO. 2

August 2016

PHYSICAL CHARACTERISTICS OF ENERGY

> POWER VS. ENERGY
> Power is the instantaneous flow of electricity, or current – that is, the rate of electricity production, transfer or demand. Under the International System of Units, it is measured in watts. Energy is the amount of power consumed over time, which is measured in watt-hours.
>
> ENERGY = POWER X TIME
> For example, if a generator produces 100 megawatts (MW) of power for two hours it creates 200 megawatt-hours (MWh) of energy. The average household consumes about 900 kilowatt-hours (kWh) per month.

INTRODUCTION

Electricity is the flow of electrical charge. It occurs naturally, but must be created and distributed in particular ways to make it useful to people. The physical fundamentals of electricity define how we build and use electric infrastructure to ensure reliable service to customers.

The vast majority of electricity in the United States is generated by large power plants and transferred to customers through the "grid." The grid, or transmission system, is a network of power lines and equipment used to transport electricity in bulk from power plants to communities. At the local level, distribution lines and equipment transfer power from the transmission system to end-use customers. Increasingly, customers also generate electricity on-site to meet some or all of their needs, most commonly through rooftop solar panels.

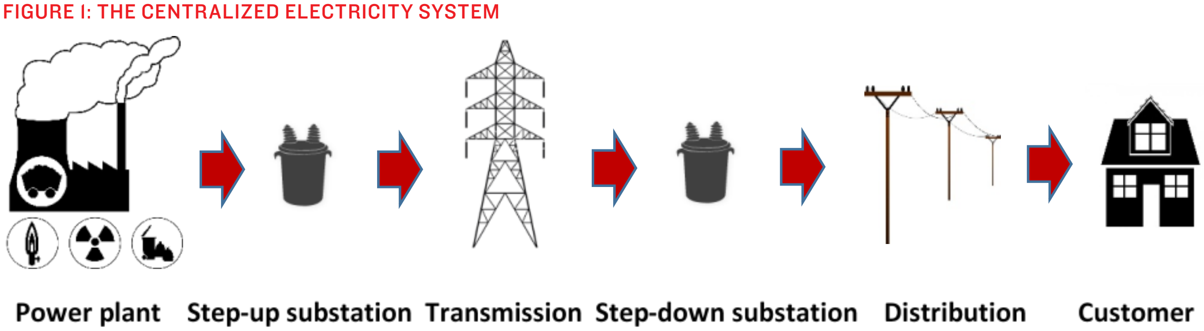
Electricity is a secondary energy source derived from a primary source. Primary sources include chemical energy stored in fossil fuels and biomass; kinetic energy from wind or solar; nuclear energy stored in the nuclei of atoms; or gravitational energy stored at an uphill dam. This energy converts to mechanical energy that spins or rotates magnets around wire coils, which thus induce electrical currents and voltages.

Voltage is a measure of the electromotive force of electricity. This can be thought of as the "pressure" of electricity, similar to the pressure in a waterline. A substation "steps up" the voltage of electricity generated in power plants to transport it via high-voltage transmission lines. Higher-voltage lines transfer power more efficiently over long distances. The bulk or "wholesale" transmission system operates lines that range in capacity from a few thousand volts to as much as 750,000 volts. This system delivers power to retail distribution systems, where other substations "step down" the voltage for local distribution to customers on low-voltage wires.

SYSTEM OPERATION

To maintain reliability, the U.S. electric system seeks to keep the system frequency near 60 hertz, but imbalances in supply and demand cause deviations from that target. Severe

FIGURE 1: THE CENTRALIZED ELECTRICITY SYSTEM



deviations can cause problems in the quality and reliability of electric service, such as brownouts and blackouts. This challenge is exacerbated by the practical limits to storing electricity in a cost-effective way. Thus, the system must balance generation and demand simultaneously, which requires generation output to be adjusted constantly to match fluctuations in demand.

There are a variety of operational limitations that generation facilities face which constrain their ability to match changes in demand. Generators vary in how quickly they can adjust their output. For example, natural-gas-fired generators generally can alter their output more quickly than coal-fired generators. Generators also have a limited "dispatch range," which refers to the difference between their maximum and minimum output. Most fossil and nuclear units require hours or even days to start. Generators also may be limited in how frequently they can start and stop within one or several days. Units with better operational abilities provide more supply flexibility to match fluctuations in demand. For example, natural-gas combustion turbines can start in a matter of minutes and be turned on and off multiple times a day.

Electricity demand, or "load," fluctuates within each hour, varying considerably based on the time of day and weather patterns. Demand also varies greatly by location. The geographic dispersion of generation facilities and demand, along with transmission-system limitations, results in transmission congestion. Transmission congestion limits the ability to dispatch generation to meet demand in constrained areas. This often occurs in high-demand areas, such as cities, where transmission constraints limit the ability to import power from far away.

Balancing the electricity system involves coordinating generators' dispatch to meet demand. This requires anticipating demand, a process known as "load forecasting." To prepare for changes in demand, a grid operator must pre-position generators (i.e., turn them on and schedule their operation) hours or even days in advance, based on their operating characteristics and location. Real-time adjustments become necessary to correct for unanticipated developments, such as load-forecast errors or system contingencies. Reserve generation resources can address major contingencies, like a sudden mechanical failure at a generation facility or loss of a transmission line. The rise of wind and solar resources, whose output varies with weather conditions, introduces a challenging supply-side variable to balancing the grid.

SYSTEM PLANNING

Maintaining a reliable system requires long-term planning to ensure future demand can be met adequately. Large generation and transmission facilities take three or more years to build. Planning requires determining the appropriate size of generation, transmission and distribution facilities to meet the maximum amount of power consumers will demand at any given point in time. Specifically, this requires sufficient generation capacity, or maximum output, to meet peak load, plus a reserve in the event of a system contingency.

POWER PLANTS ARE LIKE SPRINTERS

Power plants' abilities can be analogized to those of elite athletes:

- How fast a sprinter runs is akin to a plant's "dispatch," or level of output.
- How quickly a sprinter accelerates is akin to "ramp," or the rate of change in output.
- A sprinter's top speed is akin to a plant's capacity, or maximum output.
- An athlete's responsiveness is similar to the time a plant needs to begin producing power.
- The short- and long-term performance of both athletes and power plants depends on conditioning (e.g., equipment maintenance).
- The performance of both athletes and power plants can be sensitive to weather conditions (e.g., high heat lowers the output of many plants).

Planners use long-term load forecasting to provide an estimate of peak demand. Demand-side management programs, such as promoting weatherization and high-efficiency lighting, can reduce the need to invest in generation and transmission. Transmission and distribution system planning must also provide for sufficient transfer capability to accommodate electricity flows at peak periods in all locations.

Electric-system planning must address both the expected and unexpected. Changes in technology, policy and demand are difficult to predict. Planners must account for risks and uncertainties, such as economic shifts that affect load growth, changes in regulatory requirements and the rise of disruptive technologies that affect load or customer self-generation. For example, policies that promote wind and solar generation may create the need for additional flexible-generation services, such as quick-start and fast-ramp capability. Future unknowns, combined with the long-term nature of electricity infrastructure, amplify the importance of risk and uncertainty management in electricity planning.

CONTACT
If you have questions regarding this subject, please contact Electricity Policy Manager Devin Hartman or Outreach Director Lori Sanders at the R Street Institute at 202-525-5717.

Free markets. Real solutions.

R STREET'S ELECTRICITY 101 SERIES
NO. 3

August 2016

ECONOMIC CHARACTERISTICS OF ELECTRICITY

INTRODUCTION

The physical fundamentals of energy inform the economic fundamentals of electricity. Power plants that generate electricity face both fixed and variable costs. Fixed costs do not vary with the level of output; they primarily include capital costs and land costs associated with building a facility. The costs faced by transmission and distribution facilities are almost entirely fixed.

The variable costs of electricity – including fuel, labor and maintenance costs – depend on a power plant's level of output. Over the short term, these are captured by looking to a plant's marginal cost – that is, the cost to produce one more increment of output. Marginal cost provides the conceptual basis for cost-effective operation of the electricity system.

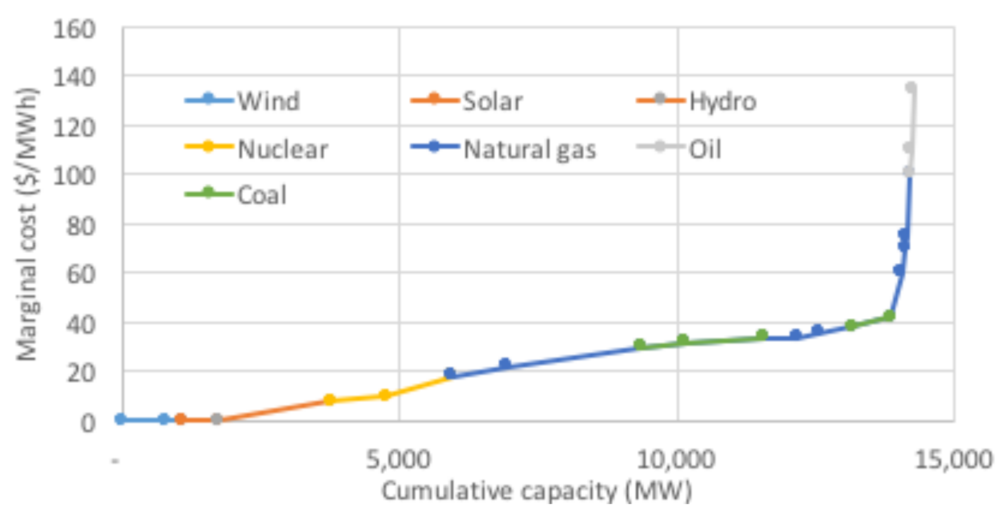
OPERATIONAL ECONOMICS

Unique short-term supply-and-demand characteristics make electricity an unusual product. Notably, all producers and consumers require access to a shared network (transmission), where the actions of some participants can affect the quality of service received by others. The challenge of balancing supply and demand is compounded by the lack of cost-effective storage options, like batteries. This makes the system very sensitive to short-term supply and demand shifts.

Historically, consumers had no way to assess real-time grid conditions for themselves, meaning they also had no way to adjust their consumption accordingly. Advances in technologies and services have given customers new information about grid conditions, like high costs on hot evenings or low costs on cool mornings. Nonetheless, most customers remain unresponsive to these changing grid conditions, which can cause rapid fluctuations in the marginal cost of generation. Some large consumers are a notable exception and change their demand according to grid conditions in order to save money on their bills.

Operating the grid in the "least-cost" manner requires minimizing generation costs. This involves dispatching gen-

FIGURE 1: AN ILLUSTRATION OF TYPICAL ENERGY SUPPLY CURVE



erators in order of lowest to highest marginal cost to meet demand. The primary component of marginal cost for generators is fuel. This is determined both by fuel cost and by the efficiency with which a generator converts fuel into electricity. The result largely drives the shape of the supply curve. Fuel costs vary little over months for coal and nuclear generators, who usually sign long-term fuel contracts. Natural gas costs can vary substantially between and within a day, which shifts the supply curve considerably. Wind and solar, given their free fuel supply, have marginal costs near zero. Their dependence on the weather shifts the supply curve considerably. Most generators also incur substantial costs to start, shut down and adjust their output.

The marginal cost to serve demand, or "load," in a particular area depends on the marginal cost of generation and the typically small "line loss" associated with transmitting power over transmission and distribution lines. Load also is limited by transmission availability. If power from the least-cost generator cannot flow to a load area because of constraints on the transmission system, the least-cost generator who can serve that load moves up in the dispatch order. The difference between these two generators' marginal cost is referred to as the "marginal cost of transmission congestion." This represents the extra cost to satisfy demand when transmission constraints require generation to be redispatched.

TABLE 1: ECONOMIC CHARACTERISTICS BY FUEL TYPE

Type	Fixed costs	Marginal costs
Coal	Medium	Medium
Natural gas	Low	Low to high
Nuclear	High	Low
Hydroelectric	Medium	Zero
Solar	High	Zero
Wind	Medium	Zero
Oil	Low	High

INVESTMENT ECONOMICS

Historically, units with higher fixed costs – like nuclear, hydroelectric and coal – had low marginal costs. These units would provide the lowest average cost of electricity when they were operated frequently. As such, they were built to run at a steady level in a "baseload" role – that is, to meet minimum levels of demand. It proved more cost-effective to build low fixed-cost generation, like natural gas and oil, to meet less-frequent demand needs.

In recent years, cheap natural-gas prices have usually made it more cost-effective to build natural-gas power plants in a baseload role than either coal or nuclear. Wind and solar expansion has contributed to lowering marginal generation costs, but their variability limits those sources' ability to replace conventional power plants. This is because their maximum output capability at peak periods is constrained by weather.

Electric infrastructure is capital-intensive, meaning its fixed costs are high relative to its variable costs. Spreading fixed costs out over a greater scale results in lower average per-unit costs, thus offering what are known as economies of scale. For example, building and operating a 600 MW plant is less expensive than two 300 MW plants.

Electric infrastructure also is long-lived, operating for decades at a time. It requires long lead times to build. Once built, the high fixed costs become large sunk costs (that is, costs that were already incurred) to generation owners. This magnifies the consequences of poor investment decisions. Furthermore, investment economics depends on a variety of conditions that are difficult to predict, such as fuel prices, technology advances and policy changes. All these factors make generation investment risky for investors.

These features have made long-term planning an indispensable tool to minimize cost and risk. Through a process commonly known as "integrated resource planning" (IRP), producers aim to determine the least-cost mix of resources. This involves evaluating the fuel type, size and timing of new resource investments and retirements to meet expected future demand. For example, many IRPs in recent years support expanded demand-side management programs, construction of new natural-gas-fired generation and retirement of coal-fired generation. Policy interventions that deviate from IRP principles, such as those dictating a part of the fuel mix, tend to result in higher-cost investments.

Characteristics like enormous economies of scale and the inefficiencies of duplicate transmission and distribution system investments led the electric power industry historically to be designated a natural monopoly. This meant that one firm would provide electricity at lower cost than multiple, competing firms. For example, a firm with an existing transmission network can expand its network at lower cost than a new entrant starting from scratch.

New technologies reduced the economies of scale, starting in the 1980s, as smaller generation facilities became more economical. These shifts called into question whether a single generation provider would deliver lower-cost service than multiple providers in a competitive market. Competition also could offer incentives for generators to manage risks, lower costs, innovate and provide superior customer service. This set the foundation for industry reforms in the 1990s, when electricity markets began signaling investment decisions for much of the United States.

CONTACT

If you have questions regarding this subject, please contact Electricity Policy Manager Devin Hartman or Outreach Director Lori Sanders at the R Street Institute at 202-525-5717.

Free markets. Real solutions.

R STREET'S ELECTRICITY 101 SERIES
NO. 4

August 2016

TRADITIONALLY REGULATED VS. COMPETITIVE WHOLESALE MARKETS

INTRODUCTION

In the 1990s and 2000s, U.S. states chose either to restructure their wholesale electricity markets fully or partially, or to retain regulation of vertically integrated monopoly utilities.[1] Generally, the Southeast and Mountain West states have retained the traditional regulatory model, opting not to join regional transmission organizations and independent system operators (RTO/ISOs).[2] In these regions, investments in utility infrastructure must be approved by state regulators. Utilities usually operate their own electricity systems and incorporate exchanges with other utilities. These take the form of "bilateral trading," where the price and terms of each transaction are set through a negotiation process between two parties.

Texas, Illinois, Ohio and most mid-Atlantic and Northeast states transitioned to competitive wholesale and retail markets. These areas joined or formed RTO/ISOs to operate organized wholesale electricity markets. This reduced regulation of generation and shifted some regulatory oversight of generation and transmission from the states to the federal government.[3] Today, the Electric Reliability Council of Texas (ERCOT); PJM Interconnection LLC (PJM); the New York Independent System Operator (NYISO); and ISO New England (ISO-NE) span primarily or entirely restructured states.

Some states that retained the monopoly-utility model allowed their utilities to join RTO/ISOs. Specifically, the Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP) and California Independent System Operator (CAISO) consist primarily of monopoly-utility service territories. These utilities relinquished their role as grid operators to the RTO/ISO. While these utilities "compete" in the organized markets, they generally do not use market signals to guide their behavior. State regulators still approve utility investments and their costs and market revenues are passed through to a captive customer base. The trend for utilities to join RTO/ISOs has expanded since the 2000s. In 2013, MISO integrated utilities spanning most of Arkansas, Louisiana, Mississippi and some of Texas. CAISO expanded outside of California in 2014, while SPP has also grown recently.

Utilities or independent power producers, also known as merchants, can engage in bilateral trades outside or within RTO/ISOs. Bilateral-only areas have comparatively low liquidity, in part because trading requires greater negotiation. RTO/ISOs instead use standardized electricity products in short-term markets. Bilateral-only and restructured RTO/ISO areas take somewhat similar approaches to operating their electricity systems, but sharply diverge in infrastructure-investment models.

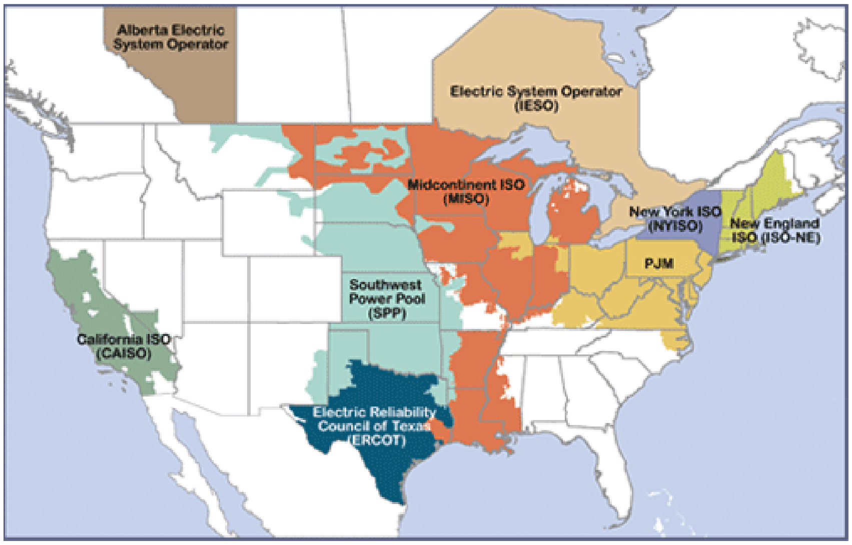
GRID OPERATION

A grid operator can be a utility, a party that has pooled utility resources or an RTO/ISO. All grid operators balance supply and demand in real time by issuing operational instructions to power plants. This begins with "unit commitment," where the grid operator signals a plant to turn on or off. Once in operation, plants receive instructions from the grid operator on the appropriate level of output, or dispatch. For example, the grid operator may "commit" a 1,000 megawatt (MW) natural-gas combined cycle plant to turn on one day in advance and then dispatch it at 800 MW (80 percent of its capacity, or maximum output). If demand increases 50 MW, the operator may increase the dispatch of the plant to 850 MW.

Pooling resources lowers the cost of dispatching an electricity system. This is what prompted the formation of "power pools" in the 1970s and 1980s. Power pools use a central dispatcher to administer interchange between utilities by dispatching the lowest-cost resources to meet demand. These served as early predecessors to most RTO/ISOs.

RTO/ISOs have more precise and advanced techniques to commit and dispatch resources than power pools. RTO/ISOs

FIGURE I: U.S. AND CANADIAN RTO/ISO TERRITORIES



SOURCE: Federal Energy Regulatory Commission

dispatch resources in five-minute intervals, whereas non-RTO/ISO areas usually do so every hour. This provides better precision to adjust generation to match rapid fluctuations in electric supply and demand. RTO/ISOs also have sophisticated modeling systems that increasingly let them "look ahead" to better position resources for expected and unexpected changes in grid conditions. This advantage becomes more pronounced with growing amounts of wind and solar generation, which increase variability and uncertainty in grid operations.

A key operational advantage for RTO/ISOs is their superior commitment and dispatch of resources to manage transmission congestion. Transmission constraints can develop quickly with great variation from location to location. RTO/ISOs use short-term markets that reflect the marginal cost to serve load at very granular geographic levels. This provides price signals that reflect market fundamentals better than bilateral-only areas.

Organized short-term markets provide superior price transparency and liquidity relative to bilateral-only markets. But organized markets do not replace bilateral transactions altogether. Rather, bilateral trading can complement organized markets, while the efficiency and transparency of organized markets benefit bilateral markets.

INFRASTRUCTURE INVESTMENT

Infrastructure investment mechanisms differ sharply between regulated utilities and merchants. A state regulator must deem a proposed utility investment prudent before allowing the cost to be passed through to captive ratepayers. Such regulatory oversight serves as a surrogate for competition in the monopoly-utility model. By contrast, organized markets harnesses competition between independent power producers.

RTO/ISOs have responsibility for short-term grid reliability and PJM, NYISO, ERCOT and ISO-NE must ensure adequate generation and transmission resources exist. RTO/ISOs generally cannot require investments of their members. Instead, they must rely on market mechanisms to create financial incentives for investment. Specifically, organized markets use price outcomes to signal investment from independent power producers. When market revenues exceed the cost of investment, it spurs new investment.

MISO, SPP and CAISO rely on regulated state processes for the long-term procurement of generation to operate the grid reliably. From a utility's perspective, these processes generally rely on least-cost integrated resource planning. Each utility planning on a separate "island" does not usually result in the least-cost resource mix for the entire RTO/ISO system. This approach also largely ignores RTO/ISO market prices, which send more accurate investment signals than an integrated resource plan would support. Given this mismatch, these RTO/ISOs have not adopted market designs fully to signal merchant investment.

A monopoly franchise removes the incentive to innovate to increase market share. Guaranteed cost recovery for "prudently incurred" expenses diminishes the incentive to control costs. The regulated model also insulates utilities from market risks and most policy risks, such as changes in fuel prices or government subsidies. This and a guaranteed attractive rate of return make utility investments relatively safe for investors. This investment appeal grants utilities cheap access to capital, but provides little incentive for them to manage risk well.

A competitive environment shifts risk management to merchants, who also have an incentive to control costs and innovate. For example, given the cheap natural gas environment of recent years, merchants have not opted not to invest in new high-risk coal and nuclear plants, as some utilities have done. Merchants have also led the way in reducing power-plant operating costs. They also have an incentive to extract revenue from markets in a manner that can harm market performance (e.g., market manipulation), which is why the RTO/ISOs and their independent market monitors use market power mitigation controls. On the whole, market monitors have determined that the outcomes of the organized markets have been competitive.

CONTACT
If you have questions regarding this subject, please contact Electricity Policy Manager Devin Hartman or Outreach Director Lori Sanders at the R Street Institute at 202-525-5717.

ENDNOTES

1. A vertically integrated utility owns its generation, transmission and distribution facilities. Under restructuring, a utility only owns the distribution facilities.

2. The domestic RTO/ISOs are ISO New England (ISO-NE); New York Independent System Operator (NYISO); PJM Interconnection LLC (PJM); Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP), California Independent System Operator (CAISO) and Electric Reliability Council of Texas (ERCOT).

3. This shift in regulatory authority did not occur in most of Texas, because ERCOT operations are not considered to constitute interstate commerce.

Free markets. Real solutions.

R STREET'S ELECTRICITY 101 SERIES
NO. 5

August 2016

TYPES OF ORGANIZED ELECTRICITY MARKETS

INTRODUCTION

Regional transmission organizations and independent system operators (RTO/ISOs) deliver reliable electricity through organized competitive markets. These markets reduce the costs to operate the grid and send long-term investment signals (e.g., resource construction, retirement and maintenance) that ensure there will be enough future supply resources to meet demand. RTO/ISOs also plan and coordinate the operation, maintenance and expansion of transmission facilities to ensure reliable grid operations.

The market price for wholesale electricity is determined by the levels at which suppliers are willing to provide an electricity product and those on the demand side are willing to pay for it. Generation and demand participate in organized markets by submitting offers and bids to sell or buy an electricity product in an organized marketplace. The RTO/ISOs run computerized market models that accept the lowest-cost offers needed to meet demand, while respecting the physical constraints of power plants, demand response and the transmission system. An RTO/ISO has discretion to commit and dispatch resources that did not clear a short-term market, if needed to maintain reliable grid operations.

TABLE 1: ELECTRICITY MARKET TYPES

Market	Purpose	Function
Energy market	Facilitate efficient actions by market participants in the short term (e.g., generation and demand response) and guide long-term investment decisions.	Uses short-term supply and demand to form prices that reflect the location-based marginal value of bulk energy.
Ancillary services markets		Uses short-term supply and demand to form prices that reflect the location-based marginal value of specific energy services.
Capacity markets (ISO-NE, NYISO, PJM, MISO only)	Facilitate efficient long-term decisions to ensure sufficient capacity to operate the system reliably in the future.	Uses an auction to procure a level of future capacity deemed necessary for grid reliability.

SHORT-TERM MARKETS

Energy markets use locational marginal pricing (LMP) to reflect the marginal cost to serve load at specific locations on the grid. LMP reflects three marginal-cost components: system marginal energy cost, transmission line loss and transmission congestion. The system marginal energy cost represents the supply/demand baseline, which does not vary across the footprint. Line losses are relatively small across an RTO/ISO. Transmission congestion is the difference maker. Congestion occurs when there is insufficient transmission capacity to run all least-cost resources. This tends to drive up LMPs in high-demand areas where transmission capacity is limited (e.g., New York City) and drive down LMPs in areas with an abundance of inexpensive generation that lack the transmission capacity to get to higher demand areas (e.g., wind power in the Midwest).

LMPs are very volatile compared to non-electricity commodities. This reflects the large, rapid shifts in electricity supply-demand balance at both the systemwide and local levels. Average energy market prices fall in the low-to-mid tens of dollars per megawatt-hour (MWh). High demand (e.g., hot days) and transmission constraints often will cause prices in the mid-to-high tens of dollars per MWh, sometimes briefly into the hundreds of dollars per MWh. Rarely, prices can exceed $1,000/MWh.

RTO/ISOs employ day-ahead and real-time energy and ancillary-service markets. The day-ahead market produces financially binding schedules for electricity supply and demand a day in advance of the operating day. This allows for lower-cost pre-positioning of power plants based on expected conditions. More than 90 percent of energy transactions are usually scheduled in the day-ahead market. As conditions change (e.g., errors in wind or load forecasts), the real-time market balances the difference between the day-ahead schedule and the actual amounts needed in real time.

Energy markets arrange the bulk of electricity flows, while ancillary services cover additional services needed to maintain grid reliability. Ancillary-services markets are tied to energy markets such that ancillary-service prices reflect and influence LMPs. "Regulation service" is an ancillary service that fine-tunes efforts to balance the grid by matching generation with very short-term changes in demand. "Operating reserves" are also needed to restore the balance between supply and demand when a generating unit unexpectedly goes offline. "Black start" resources have the ability to start without power assistance from the grid. This service is needed to restore operations in case of a full grid blackout, with compensation generally determined via an administrative process, rather than market mechanisms.

Short-term market prices offer signals to guide resource planning and investment decisions. Specifically, existing or prospective resource owners will retain or build resources if revenue from energy and ancillary-services markets exceed their resource cost. Otherwise, they will retire or opt not to build the resource in question. The Electric Reliability Council of Texas (ERCOT) relies exclusively on this model, employing robust "scarcity pricing." Scarcity pricing is a mechanism to send price signals in the real-time market when there is a systemwide shortage of power reserves. Without this scarcity pricing, the energy and ancillary service markets might not give facilities enough revenue to stay open, jeopardizing a system's reliability. This revenue shortfall is often referred to as "missing money."

CAPACITY MARKETS

Capacity markets present one option to address the "missing money" of short-term markets. They set a procurement target for the amount of capacity needed to meet expected future demand reliably. If facility operators aren't taking in enough revenue in the short-term markets, they have an incentive to make up that "missing money" in the capacity markets.

The interplay between short-term markets and capacity markets is similar to squeezing one side of a balloon. Price pressure in short-term markets shifts price pressure in capacity markets in the opposite direction. For example, downward pressure on short-term market prices from low natural-gas prices has decreased revenues for most generators, which increases their "missing money." This drives an increase in their capacity offers and puts upward pressure on capacity prices.

Making promises in the capacity market can come at a cost. If a facility fails to deliver its promised capacity because of an equipment failure or problems accessing fuel, it has to pay a penalty. PJM and ISO-New England (ISO-NE) recently increased their penalties greatly.

> Energy markets are the bread-and-butter of RTO/ISOs. They comprise the vast majority of transactions and costs to customers, even in RTO/ISOs with capacity markets. For example, energy markets totaled 65 percent of the 2015 total cost in the PJM Interconnection (PJM), followed by the capacity market (20 percent), transmission services (12 percent) and other services (3 percent).

Capacity markets have inherent limitations, and poorly account for things like transmission constraints and the transient value of reliability (e.g., system resource needs are much higher on a hot summer day than a mild fall day), , all of which can be reflected in the short-term market. Because of these limitations, capacity markets require extensive administrative rules. A wide degree of variance and controversy exists over capacity-market design. For example, the capacity markets in PJM and ISO-NE are held three years ahead of the delivery period to provide a longer-term signal to resource developers, whereas the Midcontinent Independent System Operator (MISO) and New York Independent System Operator (NYISO) hold theirs weeks or months in advance.

TRANSMISSION OPERATIONS AND PLANNING

Competitive, organized markets require equal access to the transmission system. To provide this, RTO/ISOs offer two primary types of transmission service: network service and point-to-point service. Network service refers to the transmission of energy from an RTO/ISO's network-generating resources to network loads, and serves as the primary priority of the transmission system. For bilateral transactions, like the sale of power from a power plant to a single customer, RTOs/ISOs provide point-to-point service. This uses the transmission system to transmit energy between a point of receipt and point of delivery. RTO/ISOs approve or deny customers' requests for transmission service based on anticipated effects on the transmission system.

RTO/ISOs are also responsible for transmission expansion, which affects the performance of organized markets. RTO/ISOs conduct systemwide transmission planning processes with their stakeholders. These identify transmission-system additions and improvements for reliability and market benefits. RTO/ISOs are in different stages of implementing disparate frameworks for competitive transmission planning. Competitive processes and cost recovery of transmission projects remain contentious, evolving topics.

CONTACT

If you have questions regarding this subject, please contact Electricity Policy Manager Devin Hartman or Outreach Director Lori Sanders at the R Street Institute at 202-525-5717.