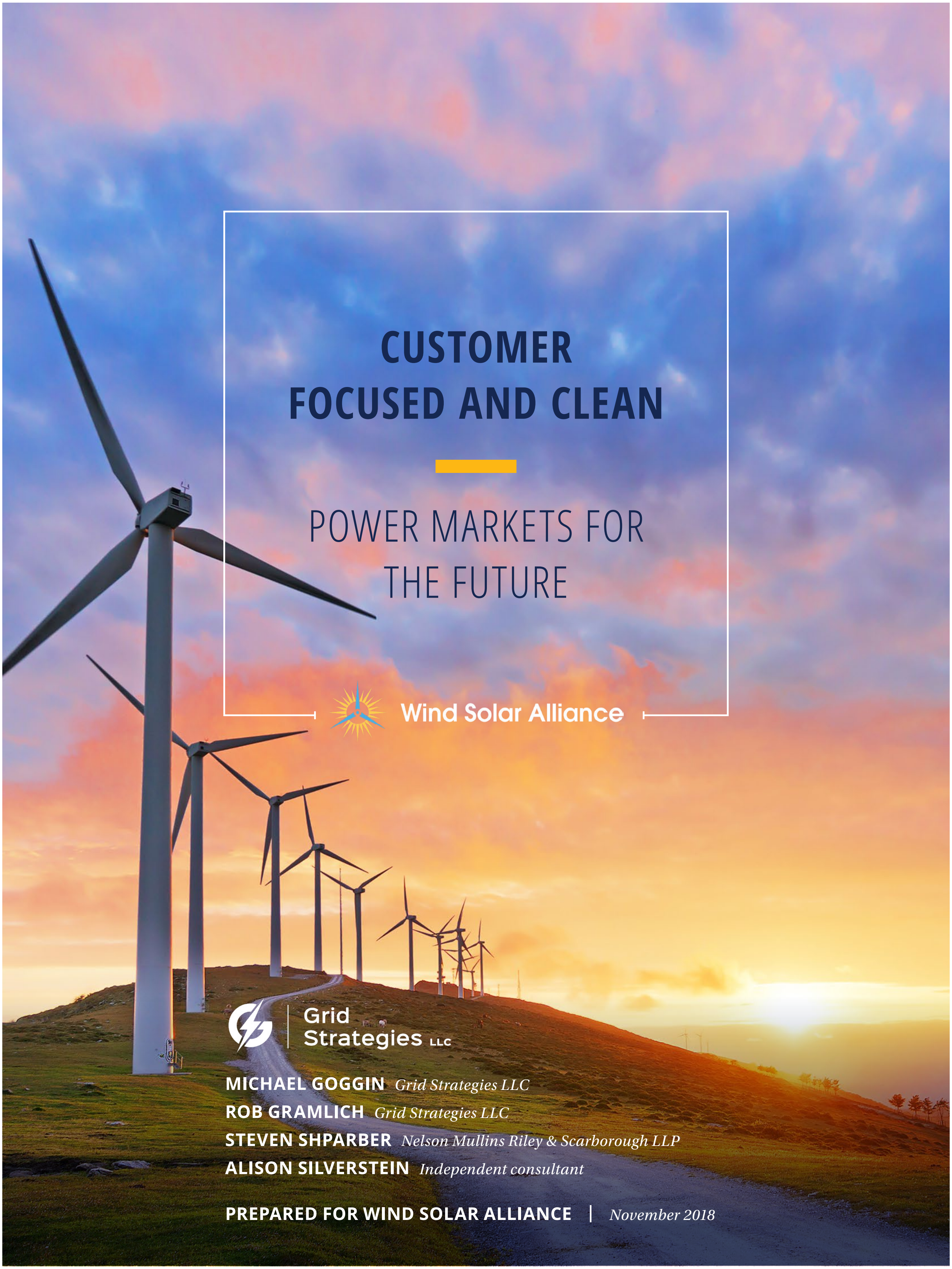

CUSTOMER FOCUSED AND CLEAN

POWER MARKETS FOR THE FUTURE

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SECTION 1
INTRODUCTION AND EXECUTIVE SUMMARY

Wind and solar energy are leading sources of new electricity generation, driven by increasing demand and rapidly declining costs. The shift in generation types will affect the whole electric industry — generation, system operations, transmission and distribution.

This report focuses on the wholesale power markets and system operations aspects of the electric industry, with particular focus on the Mid-Atlantic ("PJM") and Midwest ("MISO") regions. Two-thirds of the electricity in America passes through centralized wholesale electric markets, serving much of the nation's economy and population. Those market rules and practices are developed by stakeholders in those markets, overseen by federal energy regulators and affected by state regulatory decisions. The market rules determine how the grid operates, which resources get financing and interconnection, what products are offered, what resources get paid, and more. Market rules can make or break the economics of an individual supply or demand resource, and the reliability and affordability of electricity.

Many of the current market rules were originally designed and adopted in the 1990s and early 2000s, based on the grid operations protocols from earlier decades when the grid was dominated by large, slow-moving fossil-fired, nuclear and hydroelectric resources. There were few wind and solar generators, independent power producers, and non-utility electricity purchasers. Since that time, there have been sweeping changes in electric fuel costs, technology capabilities, market structure and customer preferences, as well as computing power and communications technology to better manage the system.

This paper offers recommendations for how to update wholesale electric market rules to better serve customers' and regulators' desire for clean, affordable electricity. These recommendations seek to align wholesale market rules more closely with several considerations: the growing demand for clean, low-cost renewable generation, energy efficiency and distributed generation; the need for reliable, affordable electricity necessitated by a challenging global economy; and federal and state mandates requiring fair, non-discriminatory opportunities for all providers, technologies and customers.

The Wind Solar Alliance (WSA, formerly the Wind Energy Foundation) is working in partnership with the American Wind Energy Association and Solar Energy Industries Association on a research and educational campaign called A Renewable America (ARA). As part of this effort, WSA hired a team assembled by Grid Strategies LLC (GS) to research and offer recommendations on how wholesale electric power markets should be designed to foster a reliable, affordable and clean electric system given current trends in energy technologies and economics. WSA also asked the GS team to recommend paths toward that improved market design within the PJM and MISO regions.

The GS team embarked upon an extensive literature review and expert survey to develop key findings and recommendations about changes needed to ensure a reliable and low-cost power system with much higher levels of wind and solar resources. Experts consulted include wind and solar developers, renewable customers, RTO stakeholders and staff, and other electric sector experts.

Markets that work for renewable resources must foster and facilitate success for all resources that support system reliability, including conventional and renewable generation, demand-side and storage resources. Transmission infrastructure and interconnection issues also have major impacts on markets, affecting resource participation timing and economics; but those issues are not in the scope of this study.

1.1 CONCLUSIONS AND RECOMMENDATIONS

This report concludes that market reforms are needed to ensure that electricity in the U.S. is reliable and affordable. Such reforms also are needed to accommodate an anticipated supply mix with high levels of renewable generation and to integrate all of the generation, storage and demand-side resources that contribute to reliable power system operation. The reforms we recommend will produce four highly beneficial features: markets that are *flexible, fair, far,* and *free.*

- **FLEXIBILITY** refers to both the market and the power system. A flexible power system should be able to respond and adapt to changes in uncontrollable or non-dispatchable factors such as consumption (load), wind speed, solar insolation, other generator output deviations, forced generation outages and transmission disruptions. Modern grid response capabilities need to be faster and cover more megawatts than in the past. Fortunately, modern computing, communications, and control technology, including the fast controls of inverter-based resources, allow much faster response than was previously possible. The market design must also be flexible enough to serve a variety of alternate resource and load scenarios effectively without the need for drastic redesign.

- A **FAIR** market will treat all customers and resources evenly and allow all the opportunity to succeed. Such a market will be designed around service requirements and performance capabilities and be fuel-neutral and technology-agnostic, without inappropriately advantaging or penalizing particular customers or resources. It will compensate based on objectively metered services delivered, rather than subjectively determined resource capabilities or attributes.

- A **FAR** market will have a broad geographic span, to maximize the efficiency benefits of supply and demand diversity,

reducing variability of resources by netting them out against each other. It will expand deliverability options between resources and customers. System operator borders will operate seamlessly and RTOs will expand in their geographic scope.

- A **FREE** market facilitates customer choice and does not raise barriers to market entry and exit. It should also support customers', states', and local authorities' ability to act on choices about how to balance between goals such as least-cost, distributed versus centralized, environmental impact, local and in-state development, and other priorities.

"Market design" refers to the rules of wholesale electric market operation. These rules address product definitions, the distinctions between energy, capacity and reliability services markets, resource offer (bid) practices, market power mitigation, and all of the software that manages the markets. These in turn affect, and are affected by, considerations such as which resources are able to enter and exit the markets (particularly as affected by interconnection rules) and those resources that are allowed to compete in each market. External factors such as state and federal policies to support particular resources (tradable Renewable Energy Certificates), wind Production Tax Credits, solar Investment Tax Credits, or nuclear Zero Emissions Credits affect the mix of resources on the system; market designs should efficiently and reliably manage this set of resources.

Table 1 below summarizes the principal reform recommendations for energy, capacity, and reliability services markets. Section 3 below offers greater detail on the recommended market reforms to ensure affordable and reliable power in the PJM and MISO markets and allow continued growth in renewable energy.

TABLE 1. *Recommended Market Reforms*

ENERGY MARKET REFORMS	RELIABILITY SERVICES REFORMS	CAPACITY MARKET REFORMS
• Ensure energy market prices reflect the value of reliability • Bring self-scheduled resources into markets • Multi-Day Unit Forecasts • Price the inflexibility costs of conventional generators • Ensure accurate, detailed generator bid parameters • Reduce operational over-commitment of conventional units • Create operating reserve zones • incent improvements in renewable energy forecasting • Probabilistic Unit Commitment • Improve gas-electric coordination • Respect bilateral contracts • Allow flexible resources to bid flexibly without being inappropriately constrained by market power mitigation rules • Allow real-time prices and demand response aggregation for electricity customers and allow demand resources to set prices - Streamline ISO seams - Use advanced grid technologies and operating practices to improve utilization of existing transmission	• Reactive power compensation • Remove barriers to renewable energy providing operating reserves like frequency regulation • Primary frequency response markets • Allow renewables to provide and set price for all reliability services • Create additional flexibility products • Make contingency reserves available to accommodate abrupt drops in renewable output	• Respect state resource choices • Allow MOPR to be avoided through bilateral contracts • Ensure capacity markets reflect renewable resources' true capacity value • Relax the requirement for capacity to perform year-round, and create seasonal rather than annual capacity products • Allow storage participation in capacity markets • Ensure conventional generators are not awarded excess credit relative to renewable resources • Efforts to add a fuel security component to the capacity market should be abandoned unless demonstrated to improve reliability or efficiency • Reform the capacity performance penalty structure to be symmetric • Allow generators to retain their Capacity Interconnection Rights (CIRs) if capacity values change • Allow hybrid projects for purposes of meeting market rules

In summary we recommend the following changes:

- Attract flexible resources including demand response and storage through open participation and efficient market pricing;
- Reduce inappropriate compensation and commitment of inflexible units;
- Allow renewable resources to participate in all reliability services markets;
- Respect resource choices by states without mitigation.

SECTION 2

MARKET DESIGN SHOULD FAVOR LOWEST COST RESOURCES WITH THE MOST FLEXIBLE CAPABILITIES

The speed of shifts in the technology and economics of different resources have outpaced the speed of policy and market evolution. Current power market designs reflect many tools and assumptions from when the grid was dominated by conventional resources, and have not yet adapted to the capabilities and demands of newer technologies and fuels or taken advantage of the advances in computing and control technologies now available. Given that these newer technologies often outcompete conventional resources on cost and environmental performance, market design changes will be needed to accommodate them.

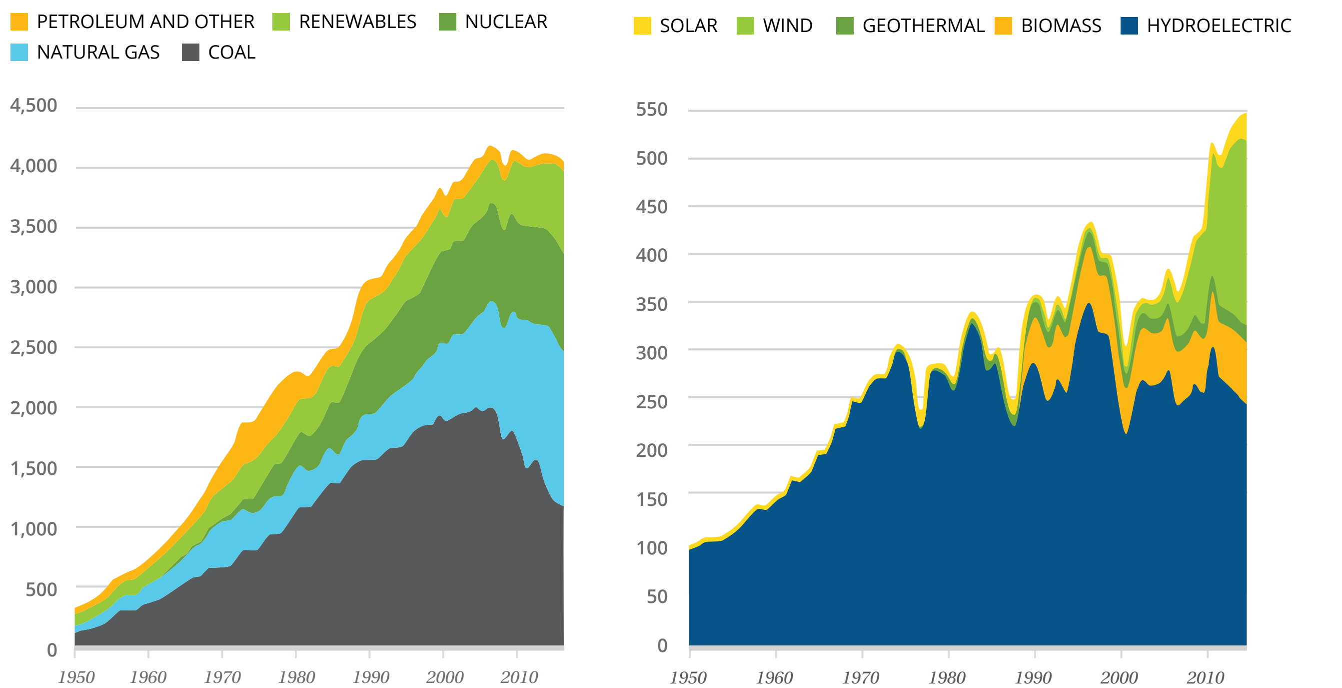
2.1 THE RESOURCE MIX WILL BE VERY DIFFERENT GOING FORWARD

The resource mix has changed dramatically in all regions over the last few decades, due to a combination of consumer preferences, economics, technology and policy changes.   The evolving resource mix is shown in Figure 1.

FIGURE 1. *Dramatic changes in U.S. electric generation mix and renewable energy sources, 1950-2017*
(Source: EIA (undated))

U.S. ELECTRICITY GENERATION BY MAJOR ENERGY SOURCES | *1950-2017*
billion kilowatthours

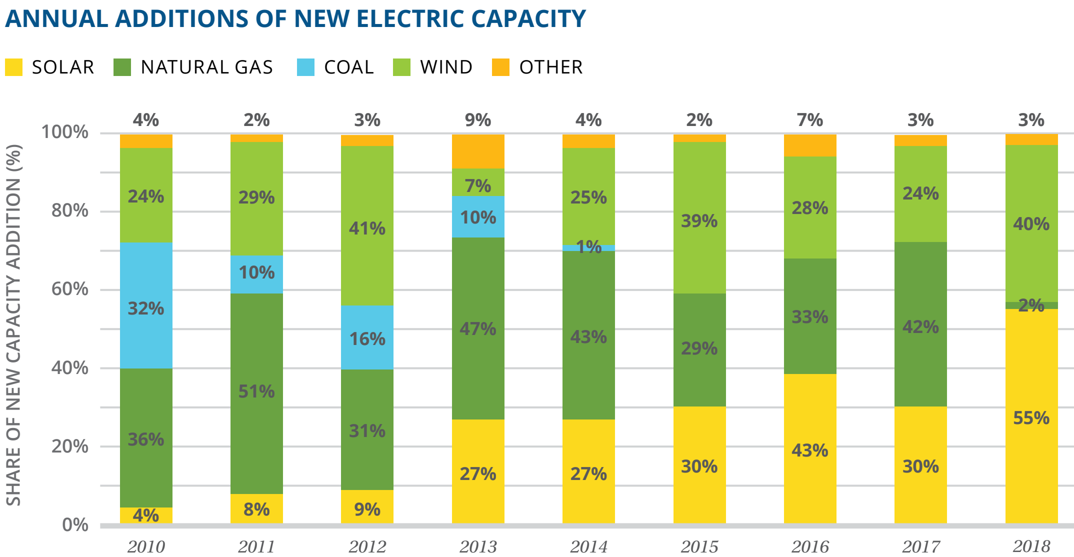
U.S. ELECTRICITY GENERATION FROM RENEWABLE ENERGY SOURCES | *1950-2017*
billion kilowatthours



Wind and solar generation continue to experience rapid growth across the U.S. Installed wind capacity has tripled over the past decade while solar has grown by a factor of six. There is now 90,000 MW of installed wind capacity in the U.S.[1] generating 6.6% of the nation's electricity,[2] and 58,300 MW of solar capacity[3] generating 2.2% of U.S. electricity, with 69% of that solar generation at utility-scale facilities.[4] Wind and solar generating capacity has increased around 500% since 2008.[5] As Figure 2 shows, annual additions of wind and solar capacity have exceeded new installations of fossil-fired and other generation types since 2014.

1 AWEA (2018).
2 EIA (2018a).
3 SEIA (2018).
4 EIA (2018a).
5 *See* http://businessrenewables.org/corporate-transactions/.

FIGURE 2. *Annual Additions of New Electric Capacity (Source: SEIA (2018))*



A significant driver of this resource shift in recent years has been the growth of renewable energy purchasing by large corporate electricity users. These entities seek to fulfill corporate renewable energy objectives, acquire low-cost renewable energy, and hedge electricity input costs through long-term power purchase agreements at fixed prices. Since 2013, dozens of U.S. corporations have contracted 13.[5] GW of wind and solar capacity.[6] PJM expects a significant amount of future generation choices to be driven by corporate procurements.[7]

Changes in relative costs are also driving significant change in the resource mix. Over the past decade, the long-term drop in natural gas fuel prices and wind and solar costs have contributed to the retirement of 40% of the nation's coal fleet since 2010, and over a quarter of U.S. nuclear capacity has announced or is at risk of retirement.[8]

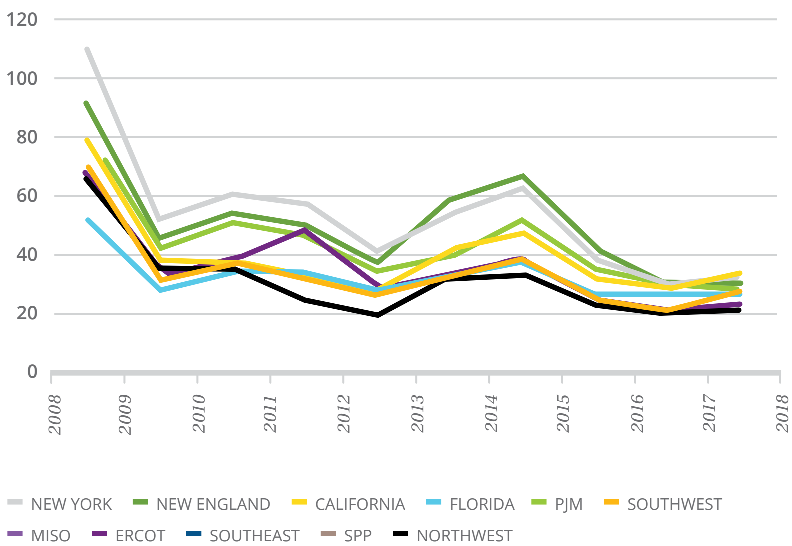
As Figure 3 shows, the addition of so much new low-cost natural gas, renewable, and energy efficiency sources has reduced prices, delivering great benefits for electricity consumers and the nation's overall economy.

6 RMI (2018).
7 Gheorghiu (2018).
8 American Coalition for Clean Coal Electricity (2018) and Loh (2018).

FIGURE 3. *Wholesale and retail electricity prices have flattened in every U.S. region* *(Source: BNEF (2018), p. 27)*

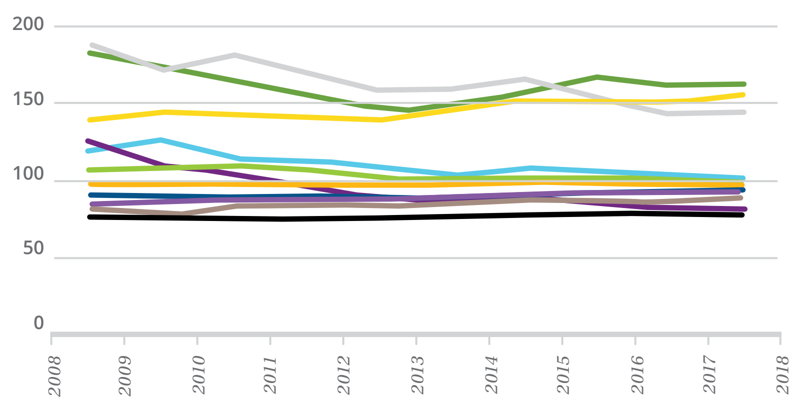
WHOLESALE POWER PRICES

$/MWh (real 2017)



AVERAGE RETAIL POWER PRICES

$/MWh (real 2017)



Most current power system forecasts anticipate the continuing growth of renewables and natural gas and retirements of older, inflexible coal and nuclear generation.[9]

2.2 CURRENT MARKETS WERE DESIGNED FOR YESTERDAY'S TECHNOLOGIES

Most of the power system planning, operations and market methods now in use were developed around the operational capabilities of large, utility-owned conventional fossil, nuclear, and hydro power plants. For example, the timing of the two-settlement market, with day-ahead and real-time clearing, was based on the typical fuel procurement timeline of gas generation as well as the start-up time for coal generators. Operating reserves were defined by characteristics of thermal generation supply ("spinning" vs "non-spinning"), rather than by system needs. "Inertia" from the rotating masses of synchronous generators was considered a product, when it is actually only one tool to stabilize frequency following a system disturbance (the other primary tool being fast frequency response, which inverter-based resources such as wind and solar plants can provide). Operating reserves needs were defined by the loss of large synchronous generators, rather than other sources of variability and uncertainty.

Transmission and generation were scheduled well in advance of the operating period, because most of the available resources were relatively inflexible, most market transactions were conducted bilaterally, and the system lacked the fast communications and computing power to set schedules closer to the operating period. Generation and transmission were operated very conservatively using fixed operating limits and schedules and contingency analysis, because operators and generating resources lacked the ability to monitor and control power system operations and respond to contingency events in real time. These are just a few of the operating protocols that underlie current market rules and are implicitly biased towards conventional generation and away from new entrants. Appendix A provides more detail on characteristics of wholesale electric markets and how they were designed around conventional utility-scale resources.

9 See EIA (2018b), MacDonald (2016), Goldman Sachs (2016).

2.3 POWER SYSTEMS CAN BE OPERATED RELIABLY WITH MUCH HIGHER WIND AND SOLAR PENETRATIONS

Studies and experiences collected around the world have shown continued reliable system operation with renewable penetrations over 50 percent. Significant research is now focusing on renewable penetrations of 80 percent and greater, where integration challenges become much more complicated and costs increase substantially. But for the next 10-20 years, the market rules and grid operations reforms suggested herein will provide enough flexibility for wind and solar penetrations to grow significantly before reaching those challenges. As a result, there will be time to develop technology and operational solutions for extremely high renewable energy penetrations.

The National Renewable Energy Laboratory (NREL) performed a comprehensive study of high renewable penetration for the U.S. Eastern Interconnection, of which PJM and MISO are significant parts. The study concluded, "While [the Eastern Renewable Generation Integration Study] shows it is technically possible to balance periods of instantaneous [Variable Generation] penetrations that exceed 50% for the [Eastern Interconnection], the ability of the real system to realize these futures may depend more on regulatory policy, market design, and operating procedures."[10]

NREL also performed the "Renewable Energy Futures Study," which thoroughly studied the grid implications of an 80 percent renewable scenario.[11] The report finds, "the central conclusion of the analysis is that renewable electricity generation from technologies that are commercially available today, in combination with a more flexible electric system, is more than adequate to supply 80% of total U.S. electricity generation in 2050 while meeting electricity demand on an hourly basis in every region of the United States."[12] The 80 percent renewable share included approximately 50 percent variable wind and solar resources and 30 percent from other resources including hydroelectric, biomass and geothermal.

2.4 RECENT FERC REFORMS ALLOWING PARTICIPATION BY STORAGE ARE NEEDED FOR ALL TECHNOLOGIES

RTO market operators currently use a model of each type resource participating in the market to calculate how each resource will interact. FERC recently issued Order No. 841, which requires all RTOs and ISOs to create a storage "participation model" and allow storage resources to participate in any energy, reliability services and capacity markets for services they are capable of providing. While some parties asked for these changes to generically apply to all resources, FERC ruled that this order was focused on storage only. FERC has not to date directed comparable treatment for wind and solar resources.

Rather than adding more technology-specific participation models for each new technology on top of the generator, load, demand response, and now storage participation models now used, FERC could replace all of these with a "Universal Participation Model." A Universal Participation Model is a technology-neutral set of bid parameters based on what characteristics matter to grid operators. FERC could propose a universal model for Order 841 compliance, as allowed in the Order, though compliance is due in the very near term and significant work would be needed at each RTO. With modern computing power and optimization methods, and the similar capabilities among all inverter-based resources, there is reason to believe all resources could submit energy and ancillary services offers to the market using the same set of parameters, which the system could then optimize.[13]

2.5 ELECTRICITY PRODUCTS AND PRICES ARE CHANGING WITH THE TECHNOLOGY AND RESOURCE MIX

Wind, solar, and battery resources are inverter-based resources[14] with different operating characteristics from conventional resources. These resources offer new ways to improve system reliability and efficiency but necessitate different approaches and assumptions about power system design, capability and operation. Market rules, tariff provisions, and NERC and regional reliability standards and guidelines do not yet capitalize on the performance capabilities of wind and solar resources and the inverters that connect them to the grid.

10 NREL (2016) at p. 154.

11 NREL (2012).

12 Ibid p. 5.

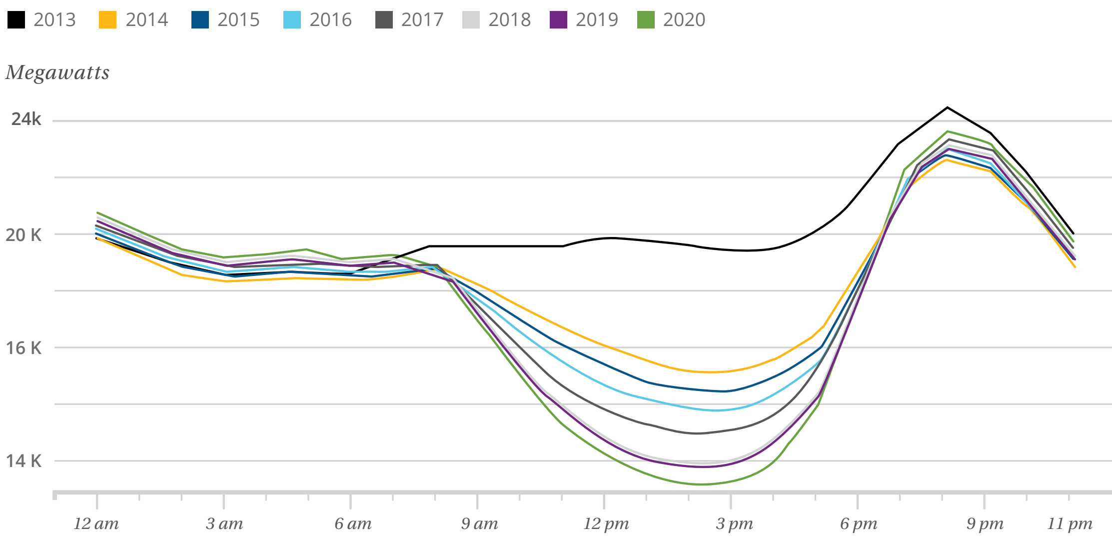
13 Ahlstrom (2018).

14 Inverter-based resources are connected to the power system by power electronics that convert Direct Current (DC) to the Alternating Current (AC) used on today's grid; conventional resources such as hydro, nuclear and fossil resources all generate AC power and feed it directly into the grid.

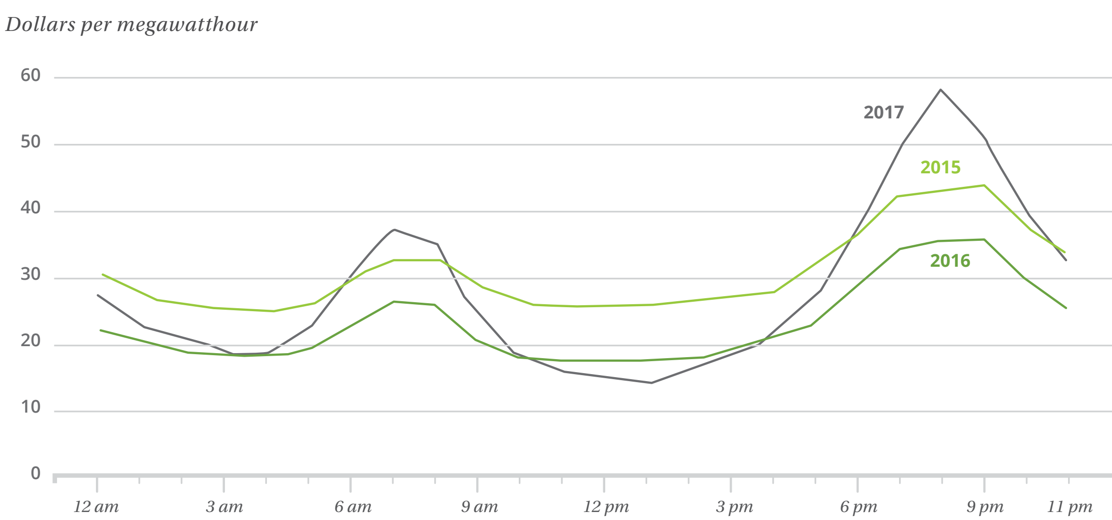
The new generation patterns introduced by wind and solar plants, as well as their variability and uncertainty, are increasing the value of power system and resource flexibility. Figure 4 shows the notorious California ISO "duck curve," in which utility-scale and distributed solar generation has caused net load (total load minus variable renewable generation) to bottom out midday and then ramp up swiftly in the evening as the sun sets.[15] This pattern drives wholesale electricity prices notably higher during the morning and evening ramps, reflecting a premium for flexible generation during those periods, as shown in the second chart.[16]

FIGURE 4. *CAISO net loads and prices show value of flexibility* *(Source: Chediak (2018) and EIA (2017))*

SOLAR'S SURGE. *The proliferation of solar farms in California has led to an oversupply of power generation in the middle of the day and steep drop-off in the evening*



CALIFORNIA INDEPENDENT SYSTEM OPERATOR AVERAGE HOURLY DAY-AHEAD ENERGY MARKET PRICES *January through June average*



This pattern is expected to continue, reducing the economic competitiveness of older and higher-cost conventional generation sources. As near-zero marginal cost resources proliferate (wind, solar, hydro and nuclear), wholesale energy

15 EIA (2017).

16 In Europe, which has experienced high levels of distributed solar for several years already, power traders refer to the diurnal price ramps needed to accommodate the daily onset and decline of solar PV as "devil horns." (See, for instance, "The Electricity Industry is Giving Europe's Traders a Headache," Bloomberg, April 25, 2018) This price pattern will continue until energy storage and automated demand response are deployed sufficiently to absorb and mitigate excess solar and wind generation.

market clearing prices will generally decline, although they may be higher during large ramps in net load.

As shown in Table 2, energy sales currently account for the majority of total wholesale electricity market revenues for all resources in PJM and MISO, followed by capacity revenues, and then reliability services revenues. Over time, however, the growth of renewable energy as a share of total generation will tend to reduce mid-day and average energy market prices while increasing the value of certain forms of flexibility and reliability services. Frequency regulation and reactive power are among the most valuable reliability services. Frequency-related services — whether from supply, demand-side or storage providers — will become more valuable because wind and solar moderately increase total power system variability at high penetrations.

TABLE 2. *Average total value of different MISO and PJM markets in 2017*

(Source: Analysis of data from MISO and PJM IMM State of the Market reports for 2017[17])

	MISO $/MWH	MISO %	PJM $/MWH	PJM %
TOTAL REVENUE/MWH	**$31.35**		**$43.67**	
ENERGY	$29.46	94.0%	$30.99	71.0%
CAPACITY	$1.79	5.7%	$11.23	25.7%
ANCILLARY SERVICES	$0.10	0.3%	$0.78	1.8%
Reactive			$0.44	1%
Frequency Regulation			$0.14	0.3%
Synchronized Reserves			$0.06	0.1%

A recent study by Lawrence Berkeley National Laboratory[18] anticipates the following price impacts from high levels of renewables:

- Average electricity prices could be roughly 20 percent lower after system-wide renewables penetration increases from 20 to 40 percent;
- Altered temporal patterns of prices over days and seasons;
- Greater price volatility;
- Altered geographic patterns of prices;
- Higher prices and greater generator revenue from reliability services as the value of flexibility increases (the study did not take into account renewables' ability to provide these services so there would be some reduction in price if that were allowed as recommended here).

17 Potomac Economics (2018) and Monitoring Analytics (2018).

18 Based on Seel, Mills & Wiser (2018), and slide 6 of the May 16, 2018 presentation summarizing that study.

SECTION 3

RTO MARKET DESIGN REFORMS WILL PROVIDE ELECTRIC CUSTOMERS ACCESS TO THE LOWEST-COST RESOURCES WHILE MEETING RELIABILITY NEEDS

3.1 BROAD MARKET CHARACTERISTICS

An effective power system should provide customers with reliable and affordable power. This section describes the reforms that are needed to accommodate an anticipated supply mix with high levels of low-cost renewable generation and to integrate all of the generation, storage and demand-side resources that contribute to reliable power system operation. The reforms we recommend will produce four highly beneficial market features: *flexible, fair, far and free*.

MARKETS SHOULD BE FLEXIBLE. Power system flexibility has always been required to accommodate fluctuations in electricity supply and demand, but the magnitude of flexibility needed is increasing with the growth of renewable energy penetration. At the same time, the combination of flattened demand and behind-the-meter generation makes the inflexibility of older fossil and nuclear units more problematic and costly for the power system as a whole. It will be important to recognize and utilize the flexibility in new resources such as demand response and battery storage, as well as inverter-based renewable resources, which can now provide very fast, flexible and affordable reliability services. Reforms are needed to ensure that energy, capacity, and reliability services markets offer free and fair competition for all resources that can provide those services, and that inflexible resources are not insulated from the costs of their inflexibility. Looking forward, uncertainties on the demand-side such as potential electrification, energy efficiency, grid-integrated customer devices, distributed generation and demand response will further test market and grid management capabilities, so market design elements must be flexible enough to adapt smoothly to these many uncertainties and changes.

MARKETS SHOULD BE FAIR. These reforms are consistent with long-standing regulatory principles of competition and cost causation, and arguably required by the Federal Power Act (FPA) from which all RTO authorities and rules are derived. The FPA requires that tariffs are "just and reasonable, and not unduly discriminatory."

MARKETS SHOULD BE FAR. Effective power markets are "far", supporting large operating areas that span an extensive portfolio of supply resources with deliverability to a large number of electricity customers, coordinating across the region for cost-effective and reliable operations. Large market areas are particularly beneficial for higher renewable penetrations, as regional pooling allows geographically diverse wind and solar resources to balance each other. RTO creation removed transmission rate pancaking, allowing free flow of electrons without "tollgate" type charges as they cross each service area, allowing efficient dispatch of the lowest marginal cost resources. Large markets facilitate wider customer choice between suppliers and technologies. Where possible, RTO boundaries should be expanded to cover areas of the country that are not yet part of RTOs. Where boundaries do exist, transactions across borders should operate seamlessly.

MARKETS SHOULD BE FREE. Wholesale power markets should facilitate states' and customers' freedom to choose the types of power they wish to consume. Twenty-nine states have enacted a Renewable Portfolio Standard.[19] Many

19 See DSIRE (2017).

corporations have signed power purchase agreements to buy clean energy, with 140 companies (and counting) signing the RE100 pledge to offset 100% of their electricity demand with renewables.[20] With the rapid decline in renewable technology and natural gas plant capital and energy costs, many regulated utilities and retail electric providers are shutting down older fossil plants and building or contracting for wind and solar energy.[21] End-use customers increasingly want to be able to acquire and mix site-hosted energy efficiency, distributed generation and storage along with grid-delivered central station energy. Wholesale power markets should enable customers to act on these preferences without creating inappropriate barriers. It violates the principle of free markets when RTOs or FERC second-guess resource choices or try to mitigate them.

Markets should also facilitate resource providers' decisions to enter a wholesale market, as with reasonable and fair interconnection and market qualification rules. Market rules should enable and not discourage market exit (subject to contractual and jurisdictional limitations), particularly by providers and resources that can no longer compete effectively.

Table 4 lists recommended market reforms. These changes benefit electric customers by giving them access to the lowest-cost resources available to meet reliability needs. The recommended reforms were developed through extensive interviews with wind and solar developers, renewable off-take customers and other electric sector experts. Each of these reforms is explained in detail below.

TABLE 4. *Recommended market reforms*

ENERGY MARKET REFORMS	RELIABILITY SERVICES REFORMS	CAPACITY MARKET REFORMS
• Ensure energy market prices reflect the value of reliability • Bring self-scheduled resources into markets • Multi-Day Unit Forecasts • Price the inflexibility costs of conventional generators • Ensure accurate, detailed generator bid parameters • Reduce operational over-commitment of conventional units • Create operating reserve zones • incent improvements in renewable energy forecasting • Probabilistic Unit Commitment • Improve gas-electric coordination • Respect bilateral contracts • Allow flexible resources to bid flexibly without being inappropriately constrained by market power mitigation rules • Allow real-time prices and demand response aggregation for electricity customers and allow demand resources to set prices - Streamline ISO seams - Use advanced grid technologies and operating practices to improve utilization of existing transmission	• Reactive power compensation • Remove barriers to renewable energy providing operating reserves like frequency regulation • Primary frequency response markets • Allow renewables to provide and set price for all reliability services • Create additional flexibility products • Make contingency reserves available to accommodate abrupt drops in renewable output	• Respect state resource choices • Allow MOPR to be avoided through bilateral contracts • Ensure capacity markets reflect renewable resources' true capacity value • Relax the requirement for capacity to perform year-round, and create seasonal rather than annual capacity products • Allow storage participation in capacity markets • Ensure conventional generators are not awarded excess credit relative to renewable resources • Efforts to add a fuel security component to the capacity market should be abandoned unless demonstrated to improve reliability or efficiency • Reform the capacity performance penalty structure to be symmetric • Allow generators to retain their Capacity Interconnection Rights (CIRs) if capacity values change • Allow hybrid projects for purposes of meeting market rules

20 Bloomberg New Energy Finance (2018b).

21 For example, see Pyper (2018), "Xcel to Replace 2 Colorado Coal Units with Renewables and Storage."

The recommendations here cover RTO market features. This report's scope does not include transmission infrastructure, interconnection, or market features that are outside of RTOs' control such as environmental attributes (RECs and emissions credits) or PPA structures, both of which can be influenced by state policy. However, transmission, interconnection, and contract considerations have significant impacts upon the ability of clean energy resources to enter and participate successfully in centrally organized spot markets and bilateral markets.

3.2 ENERGY MARKET REFORMS

We recommend a set of reforms designed to ensure that all supply- and demand-side resources and customers see price signals that accurately reflect the value of electricity, which should reflect the full cost of producing and delivering electricity in that time and place. The reforms both attract and retain sources of flexibility and ensure that inflexible power plants bear the full cost of their inflexibility.

3.2.1 ENSURE ENERGY MARKET PRICES REFLECT THE VALUE OF RELIABILITY. Any energy market offer caps should reflect the full value of providing reliable electric service during times that generation is scarce.[22] An Operating Reserve Demand Curve (ORDC) adder to the energy market price can also be used to reflect the value of scarce operating reserves during shortage events.[23] Both PJM and MISO cap energy market prices at levels below the $9,000/MWh cap used in ERCOT. MISO's Independent Market Monitor has written that, "MISO's current ORDC does not reflect reliability value, overstating the reliability risks for small, transient shortages and understating them for deep shortages."[24]

Scarcity pricing also helps incentivize needed flexibility. By allowing prices to swing high or low during periods in which flexibility is needed, it is incentivizing resources to become more flexible. In an effective power market, most customers do not actually pay the scarcity-based price, as they have been shielded by advance forward contracting for energy at reasonable costs; it is only those customers that did not plan for their needs that do pay it during the scarcity event. Scarcity pricing serves as a penalty or a speeding ticket, that exists to dissuade inefficient behavior (in this case, leaning on the system, or free riding) but should rarely have to be paid.

3.2.2 BRING SELF-SCHEDULED RESOURCES INTO MARKETS. In both MISO and PJM (and also SPP), many conventional generators are self-committed or self-scheduled by their owners rather than dispatched by the RTO through the

22 FERC acted in Order No. 831 to ensure offer caps reflect the value of reliable electricity, although that order limits offers to $2,000/MWh. See FERC (2016b).

23 ERCOT has set an energy market price cap and an ORDC that reflects a Value of Lost Load of $9,000/MWh.

24 Potomac Economics (2018) p. 86.

centralized unit commitment and scheduling process.[25] Many of these generators are owned by regulated utilities that are under the jurisdiction of state regulators, which in some cases can allow a perverse incentive for self-commitment and self-scheduling. Regulated generators pass through operating costs to utility customers, and the utility has an incentive to operate the plant to demonstrate its continued usefulness so that it can justify to regulators that the plant should remain in the utility's rate-base, where it earns a rate of return for the utility.

Both self-commitment and self-scheduling tend to increase overall system costs because the self-scheduled unit is not necessarily the least-cost unit and it may force other plants to cycle or curtail output. A plant that is self-committed and self-scheduled typically produces more energy in more hours than that plant would produce if it were to compete with other resources in the RTO's security-constrained unit commitment and dispatch process. For that reason, plants that self-commit effectively reduce the level of load to be served through the RTO's competitive market process, and thus the amount of energy that is priced at the lowest competitive level through the RTO's centralized market competition. This suppresses the energy market prices paid to all of the resources serving loads through the centralized RTO market.

There is a jurisdictional barrier to RTO and FERC remedies to the self-scheduling problem, because most self-scheduling resources are owned by utilities that are providing bundled retail service under state jurisdiction. At the same time, however, this raises a potential discrimination problem under the Federal Power Act because newer renewable and natural gas resources are generally required to be dispatchable, such as under MISO's Dispatchable Intermittent Renewables program — which applies whether or not those resources are in retail rate base. If FERC chose to address this fairness problem, a consistently applied rule could affect self-scheduled and self-committed resources within RTOs.

The economic impact of this change could be very large. Analysts have identified regulated coal plants that incur an average of about $500 million in operating losses per year in MISO and $230 million annually in PJM.[26] While some of these losses could be incurred because coal plants are too inflexible to turn down or off when energy market prices drop below the plants' cost of producing electricity, it is likely that self-scheduling and self-commitment are a significant factor in these plants' behavior. Approximately 75% of operating capacity in MISO (78% of the capacity in the day-ahead market) is self-committed.[27]

3.2.3 MULTI-DAY UNIT FORECASTS[28] COULD REDUCE GENERATOR SELF-SCHEDULING. When market participants with inflexible resources are unsure of supply and demand a few days ahead of time, utility owners tend to over-commit generation to assure they will have sufficient generation when needed. As discussed above, those units are typically fossil units, and when they are committed, they will produce energy and can displace renewable energy and suppress energy market prices. But if an RTO creates a centralized multi-day-ahead market in which resources and loads could voluntarily procure energy, this would create price signals that reflect expected electricity supply and demand, allow participants to create financial hedges against uncertainty, and yield more efficient resource commitment. With better resource commitment, there would be fewer instances when generators would have to operate at a loss over a multi-day or multi-hour period for reliability purposes, so there would be less need to pay generators "make-whole payments" (which perversely insulate a generator from the costs of its inflexibility). The financial opportunity in such a market would also encourage better forecasting of renewable output and electricity demand. If implemented well, multi-day unit commitment could tend to reduce over-commitment and over-generation that suppresses energy market prices. Importantly, participation in this market would be voluntary, and would not entitle a committed resource to any type of make-whole payment if they ended up not being needed. This ensures inflexible resources are not insulated from the system costs of their inflexibility.

Grid operators could also offer a shorter commitment window for resources that need less than a day to start up, purchase fuel, etc. In MISO some are considering rolling unit commitment based on the actual start-up time for each resource, or a potential 2-hour ahead commitment. This would improve market efficiency and reduce over-commitment by reducing supply and demand forecast error. Changes to MISO self-scheduling practices will require changes to

25 Unit commitment is the process that selects, a day in advance, which generators (and other resources) will operate the next day; scheduling and dispatch refer to hourly output levels and instructions for each resource.

26 Daniel (2018); also see the same author's analysis of the impact of self-scheduling in SPP at Daniel (undated).

27 Hansen, Xu et al. (2018).

28 Multi-Day Unit Commitment extends the process of committing generation resources (which has traditionally been done one day in advance through the Day-Ahead market) out several days in advance. For more information, see https://www.misoenergy.org/stakeholder-engagement/issue-tracking/introduce-multi-day-financial-commitments/ .

energy market rules, as well as planning and operating procedures. Revisions to MISO's Tariff and Manual 002 will be needed.

In PJM, this change would require major changes to PJM's energy market rules, as well as planning and operating procedures, affecting many sections of PJM's Tariff, Schedule 1 of the PJM Operating Agreement, and associated PJM Manuals. PJM's ongoing energy market price formation task force has been examining these issues since early 2018.

3.2.4 PRICE THE INFLEXIBILITY COSTS OF CONVENTIONAL GENERATORS. At present, energy market prices and dispatch do not perfectly incorporate the fact that most conventional generators have "non-convex" costs. These are essentially fixed costs that occur at various points on the resource's output curve, and are notably higher at unit start-up and lower output levels. While these costs are accounted for in unit commitment decisions, there is active RTO stakeholder debate about whether these costs should be reflected in energy market prices or be allocated as uplift costs outside the market-clearing LMP calculation.[29] In particular, debate has focused on which convex costs should be incorporated into price (start-up and no load costs, or other fixed costs as well), and for which units (quick-start units, only on-line resources, etc.).

In 2017, PJM proposed allowing a range of fixed costs to be included in the market-clearing price that would be set by many inflexible units. This would allow on-line coal and nuclear plants to set prices well above their true marginal cost of producing electricity. PJM's proposed form of Extended LMP inefficiently supports old generators that are not providing valuable flexibility; this imposes an unjust and unreasonable cost burden because it charges customers without delivering any reliability benefits, while insulating inflexible conventional plants from the cost of their inflexibility.

We recommend allowing quick-start units to set price, but not allow an expanded set of inflexible resources to set price or include fixed costs in the energy market price (as was proposed by PJM).

3.2.5 ENSURE ACCURATE, DETAILED GENERATOR BID PARAMETERS. RTOs and FERC should adopt market rules that improve the accuracy of the minimum generation levels and ramp rates submitted by generators to RTOs for dispatch determinations. This would better express the capabilities and limits of flexible and inflexible supply and demand resources and facilitate the better pricing of inflexibility discussed above in 3.2.4.

PJM bid parameters in particular need to be more detailed and accurate. Bid parameters that understate a unit's actual flexibility contribute to excess payments to inflexible units. PJM needs to know each unit's actual ramp capability to be able to dispatch available resources effectively, but many conventional units' reported ramp parameters are inaccurate. PJM's stakeholders completed a lengthy process related to operating parameters in 2017, but this is an ongoing topic of discussion. Any changes to ramp rates would impact Schedule 1 of PJM's Operating Agreement and PJM Manual 11, among others.

MISO is looking at how to improve bid parameters reporting and use, to improve system operational flexibility and price transparency. As part of this effort, MISO is attempting to reduce make-whole payments and other out-of-market compensation and replacing them with transparent prices. MISO has ongoing stakeholder discussion related to improving bidding parameters and improving price transparency. Any revisions arising from this stakeholder process will require revisions to the MISO Tariff and MISO Manual 002, among others.

3.2.6 REDUCE OPERATIONAL OVER-COMMITMENT OF CONVENTIONAL UNITS. RTO operators act conservatively to protect grid security. They tend to commit more conventional units within the operating day than official schedules say are needed, to ensure that sufficient resources will be available to meet later contingencies.[30] This excess supply decreases market-clearing prices — which underpays all power producers — and keeps more inefficient, inflexible units on-line. Experts interviewed suggest that MISO operators commit additional flexible resources they know they will need. Committing flexible units is beneficial for system reliability, but it should be done based on transparent market signals to attract and retain flexible supply sources rather than administratively outside the market.

As noted below, probabilistic unit commitment methods can help operators better manage risk, yielding more efficient

29 FERC has proposed bringing start-up and no-load costs into energy market prices, but only for fast-start generators. See FERC (2016c).

30 This dispatch of excess units occurs even though the extra units called up are not required under the official dispatch plan for the day or hour.

commitment and dispatch.

Changing operational practices does not require any changes to RTO tariff or manuals per se.

3.2.7 CREATE OPERATING RESERVE ZONES. RTOs could implement operating reserve zones to ensure that prices match the value of operating reserves, particularly where transmission congestion frequently creates different costs for operating reserves on different parts of the system.[31] Operating reserve zones allow operating reserves to trade at different prices in different parts of the RTO if transmission congestion prevents the delivery of operating reserves from one area to another. This would attract flexible resources where they are needed by improving the locational accuracy of short-term operating reserves pricing, particularly during shortage periods when it is most needed.

PJM is currently evaluating changes to its shorting pricing rules in its price formation stakeholder group. Changes to PJM's shortage pricing rules will require revisions to PJM's Tariff, Operating Agreement and PJM Manual 11.

Revisions to MISO's Tariff and MISO Manual 002 would be needed to implement changes to its shortage pricing rules.

3.2.8 ENSURE THAT MARKET RULES INCENT IMPROVEMENTS IN RENEWABLE ENERGY FORECASTING, WITHOUT UNDULY PENALIZING RENEWABLE RESOURCES FOR THEIR INHERENT UNCERTAINTY. The RTO should develop daily centralized wind and solar energy forecasts, even as market participants (including generation owners and virtual traders) should be allowed to use private forecasts to develop their day-ahead and real-time energy market offers. The freedom to use private forecasts can incentivize improvements in market participants' forecasting and allow market participants to efficiently hedge against risks identified in their forecasts.

At the same time, market rules should not unduly penalize renewable resources for their inherent uncertainty. FERC acknowledged this inherent uncertainty when it exempted renewable resources from third-tier imbalance charges in

31 Operating reserve zones were discussed in recent FERC technical conferences on price formation and are used in some RTOs/ISOs. See page 6 at FERC (2015).

Order 890.[32] Some have advocated removing that exemption;[33] in MISO some have advocated allocating a share of uplift costs, which result from supply and demand deviations from day-ahead schedules, to wind generators. However, uplift costs would not exist if the generating fleet were more flexible, so at least part of the cost-causation for such costs is due to the inflexibility of some conventional generators.

In PJM, renewable generators are allocated some share of uplift costs (Revenue Sufficiency Guarantee and Operating Reserve costs) for renewable forecast errors, creating an incentive for accurate forecasts. Because those two cost elements are tied to PJM LMPs, and low natural gas prices cause the LMPs to be low in many hours, those penalty signals do not cost much at this time. But penalties for forecast errors would rise in the future if gas prices rise.

More importantly, all resources impose integration costs on the power system, yet the vast majority of the costs are paid by all load rather than directly assigned to the generator causing them. For large or inflexible conventional power plants, that includes the costs of contingency reserves, as well as the cycling cost imposed on other resources due to the inflexibility of some resources.[34] In contrast, most short-term fluctuations in renewable output have little impact on total system variability, as those short-term fluctuations are uncorrelated and tend to cancel out against each other and against random fluctuations in load.[35] Imposing penalties on renewables that do not reflect actual costs or cost causation is inefficient and can incentivize suboptimal behavior that increases costs for customers.

3.2.9 PROBABILISTIC UNIT COMMITMENT. If RTOs used Probabilistic Unit Commitment methods to commit resources in Day-Ahead Markets, rather than the deterministic methods that are used today, it would produce more efficient and flexible system operations. Operators are making conservative unit commitment and dispatch decisions in part because they recognize that their deterministic methods and forecasts and not fully accounting for uncertainty and risk. Using more rigorous quantitative methods to account for that risk would produce more efficient, lower-risk operations. System operators in the RTO control room should not have to rely on their subjective judgments, nor take unilateral, undocumented actions that lead to blame if that judgment turns out to be incorrect. While human operators have many advantages relative to computers due to their deep knowledge of the system developed over years of experience, operators deserve better decision support tools that identify statistical patterns and use probabilistic methods to make better, lower-risk commitment and dispatch decisions.

The renewable output and electricity demand forecasts that are commercially available today typically include detailed information about the uncertainty of those forecasts, yet that information is not used in a rigorous way to improve commitment decisions. Most forecast vendors can quantify the uncertainties around a production forecast, such as uncertainty about the magnitude of a weather event versus its timing. Probabilistic Unit Commitment tools that incorporate such uncertainties would yield more efficient commitment of resources based on risk-managed inter-temporal solutions, minimizing inefficient dispatch and uplift costs. On net, this would reduce generation over-commitment.[36] Many resource owners are already using probabilistic methods to make decisions about the dispatch of energy-limited resources like energy storage, so it makes sense to also move RTO operations in that direction.

3.2.10 IMPROVE GAS-ELECTRIC COORDINATION. Further reforms beyond those in FERC Order No. 809 would improve coordination between gas and electric markets in ways that bring more flexibility into the power system. These should include reducing and synchronizing gas and electric scheduling lead times, removing unnecessary inflexibility associated with take-or-pay gas contracts, and minimizing other inefficiencies.[37] State and gas LDC natural gas demand response programs would enable better gas allocation across a gas region and between users at times of maximum gas demand.

3.2.11 RESPECT BILATERAL CONTRACTS. Bilateral contracts (Power Purchase Agreements) allow customers to procure services and attributes that are not explicitly valued and priced in the energy market, such as on-site fuel, environmental attributes, or protection against fuel price risk. Bilateral contracts also provide a way for customers to hedge against spot market price volatility and uncertainty, while in return providing project developers with the business certainty needed to invest in capital-intensive generation projects. Bilateral contracts are entirely compatible with

32 FERC (2007).
33 FERC (2012).
34 Milligan, Ela et al. (2011).
35 Holttinen (2016).
36 For background on probabilistic unit commitment, see Ela (2010).
37 Existing efforts at gas-electric coordination are discussed at https://www.ferc.gov/industries/electric/indus-act/electric-coord.asp.

centrally-operated spot markets. To ensure efficient dispatch based on marginal cost, energy purchased under bilateral contracts and self-supply — even that procured by vertically integrated utilities to serve their native load — should be dispatched through the centralized wholesale energy market.

Appendix B describes bilateral contracts and their importance to generation development including renewable energy.

3.2.12 ALLOW FLEXIBLE RESOURCES TO BID FLEXIBLY WITHOUT BEING INAPPROPRIATELY CONSTRAINED BY MARKET POWER MITIGATION RULES. Market power mitigation rules generally limit resources' bids to their marginal operating costs (heat rate times fuel cost for a typical fossil plant). That method, while justified for conventional resources to achieve competitive prices where true supply and demand intersect, does not apply well to storage or demand resources, for which the marginal cost of production is based on a temporal opportunity cost rather than the cost of fuel. The opportunity cost of storage fluctuates widely over time and is not known to market monitors.

Changes to market power mitigation rules would require significant changes to PJM and MISO's Tariffs and business manuals. Additionally, changes to these rules will require consultation first and foremost with RTO market monitors, not stakeholders.

3.2.13 ALLOW REAL-TIME PRICES AND DEMAND RESPONSE AGGREGATION FOR ELECTRICITY CUSTOMERS AND ALLOW DEMAND RESOURCES TO SET PRICES. To make the power system more flexible and encourage customers to shift electricity consumption to when energy supply is abundant, electricity customers should see prices that reflect both energy plenty and energy scarcity, if not real-time wholesale electricity prices. This would enable controllable electricity demand to be dispatched to provide energy or even reliability services. One way to achieve this is to allow load participation in the wholesale energy and reliability services markets (likely through aggregators). Another option, which is beyond the jurisdiction of RTOs and FERC and therefore the scope of this paper, is for states to implement real-time retail pricing to allow electricity users to respond to price signals. Whether implemented through state or federal jurisdiction, these changes would allow end users with automated loads to see when energy availability is high – as from night-time wind and afternoon solar generation – and consume more of that low-priced electricity, as well as reducing load in times when less generation is available and the grid may be experiencing scarcity or emergency conditions.

Real-time pricing for end users should reduce the cost of electrifying energy-intensive sectors of the economy, like transportation, building and water heating, and industrial processes, because these loads are relatively easily shifted to time periods with lower prices. This would facilitate further electrification and increase demand for low-cost renewable energy, and also enable better utilization of transmission and distribution infrastructure.

FERC is expected to issue a final rule related to DER aggregation in RTOs at some point in the future, arising from its 2016 NOPR on the same subject and April 2017 technical conference.

PJM is far ahead of MISO in terms of allowing DER aggregation, and has a standing subcommittee dedicated to addressing DER-related issues.

MISO is starting to look at DER-related issues, particularly through its storage-related task force.

Any rules related to DER aggregation and better real-time pricing signals will require significant changes to PJM and MISO's Tariffs and business manuals.

3.2.14 MORE EFFICIENT CONGESTION MANAGEMENT. In the operational time frame, transmission and market operations are inextricably linked. The energy market runs on a "security-constrained" economic dispatch that respects transmission constraints and creates prices reflecting congestion. Transmission constraints and congestion are to some degree under the RTO's control. Several practices can help to alleviate the congestion and curtailment that renewable generators (in particular) face in operations.[38]

- **STREAMLINE ISO SEAMS.** MISO, PJM, and SPP should work together to reduce wheeling costs and other "friction" for transactions across RTO/ISO market seams, including implementation of coordination transaction scheduling.[39] RTOs

38 This list does not address the longer "planning" time frame within which new infrastructure can be added.

39 This also includes reforms to pricing methods across the interface. See, e.g., MISO IMM State of the Market Report https://www.potomaceconomics.com/wp-content/uploads/2018/07/2017-MISO-SOM_Report_6-26_Final.pdf.

should further reduce “pancaked” transmission rates that increase the cost of transmitting electricity across multiple balancing areas. This is particularly problematic for wind energy traveling from MISO into PJM and across MISO South from SPP to the Southeast.

- **USE ADVANCED GRID TECHNOLOGIES AND OPERATING PRACTICES TO IMPROVE UTILIZATION OF EXISTING TRANSMISSION.** MISO and PJM should aggressively use advanced grid technologies such as topology control, flexible AC devices, power flow control, ambient temperature-based thermal ratings and dynamic stability limits for transmission lines.[40] The MISO IMM continues to recommend that MISO “expand utilization of temperature-adjusted and short-term emergency ratings for transmission facilities.” Over the last three years, MISO’s IMM has found that using ambient temperature-based line ratings could yield $127-165 million/year in benefits, with additional savings of up to half that if emergency short-term ratings are used as well.[41]

- **TRANSPARENCY REGARDING TRANSMISSION CONGESTION.** MISO and PJM should provide market participants with more information regarding transmission congestion, including scheduling of transmission outages.

3.3 RELIABILITY SERVICES REFORMS

Reliability services, also known as ancillary services, cover a range of services, beyond energy and capacity, that are necessary for the reliable operation of the power system. In RTOs, separate markets are used to procure many of these services, though some services cannot be efficiently obtained through markets so standards or cost-based rates are used instead. All power systems need the following services, at minimum, to maintain reliability; these services and the resources that can provide them are reviewed in Appendix D.[42]

VOLTAGE AND REACTIVE POWER CONTROL. Analogous to pressure in a water system, voltage and reactive power are necessary to efficiently move power and prevent power system collapse. Because reactive power does not travel far and is typically needed at specific points on the grid where a small number of resources can provide it, the service tends to be obtained through interconnection standards and cost-based compensation, rather than market procurement.

RIDE-THROUGH (RIDING THROUGH GRID DISTURBANCES). For overall grid reliability, all power plants must remain on-line for at least some number of milliseconds during a frequency or voltage disturbance caused by the failure of other power plants or transmission infrastructure. But at a certain point every generator needs to disconnect from a collapsing system to avoid equipment damage. Because minimum ride-through performance is needed from essentially all power plants, it is required through mandatory standards rather than market procurement.

FREQUENCY STABILIZATION FOLLOWING A DISTURBANCE. Primary frequency response and inertia work together to stabilize electricity supply and demand in the seconds following loss of a large conventional generator or load.

DISPATCHABILITY AND FREQUENCY REGULATION. Used to balance changes in electricity supply and demand. Frequency regulation is provided over a matter of seconds to minutes to accommodate random fluctuations in supply and demand, while resources are also be dispatched up and down by grid operators over minutes to hours in response to sustained ramps in supply and demand or the loss of a large conventional generator.[43]

BLACK-START AND SYSTEM RESTORATION. If the grid collapses, power plants disconnect from the system and shut down. If a blackout occurs, system restart requires that a few generators have the ability to restart independently, so

40 For more information on these technologies, see Gramlich (2018). Dynamic stability calculations were implemented in ERCOT about 5 years ago. This reduced curtailment by 100s of MWs and greatly reduced production costs. Made possible by advances in computing speed, this method calculates stability limit for the next 15-minute period (or faster) instead of using conservative worst-case assumptions set hours or days ahead. This allows the transmission system to carry more MWs by operating closer to its limit.

41 See Potomac Economics (2018), p. 84.

42 NERC has defined frequency support, ramping and balancing, and voltage support as essential reliability services (see NERC (2016) and pp. 17-20 in PJM (2017a). For more background on frequency-related ancillary services, see Ela (2011).

43 Operating reserves are different types of ancillary services used to keep electricity supply and demand in balance. Frequency regulation is the fastest centrally-dispatched operating reserve (in contrast to frequency response, which is typically faster but provided autonomously by resources as they sense a frequency deviation, and not centrally-dispatched by the grid operator). Every three seconds, the grid operator sends out an Automatic Generation Control signal, telling resources providing frequency regulation to either increase or decrease output based on the current balance of supply and demand. Spinning reserves are the next fastest, typically requiring response within 10 minutes, which traditionally required the resource to be online or “spinning.” Next are supplemental or “non-spinning” reserves, which typically require response within 30 minutes. Both spinning and supplemental reserves are typically only used to accommodate a contingency event in which a large generator fails due to a “forced outage,” and its supply must be replaced.

they can be used to jump-start the rest of the power system, including generators that cannot self-start. Hydroelectric plants and small oil and gas generators are typically used for black-start, as most large thermal plants cannot do so. In theory it is possible for wind and solar plants to be designed to provide black-start capability to support system restoration, but this has never been done.

For fairness and efficiency in reliability services markets, all resources that can provide a reliability service should be able to compete to do so. Customers benefit when they have access to all resources that may be able to provide a given service, and the market chooses the least cost resources. Reliability service definitions should be technology-neutral based on power system needs. As the speed and variability of North America's grids increase, more and more precise reliability services are needed to assure grid reliability, security and resilience. The following recommendations would improve reliability services markets.

3.3.1 REACTIVE POWER COMPENSATION. Compensation should be standardized and streamlined. The American Electric Power (AEP) method for reactive power compensation could be used as the standard compensation method.[44] Inverter-based resources such as wind and solar generators can provide reactive power and voltage control using the inverter, and under FERC Order 827 are now required to do so at levels comparable to conventional generators.[45] Many renewable generators currently forego the sizeable revenue they can earn for providing reactive power because of the cost, uncertainty and complexity of applying for compensation, which typically requires a litigated settlement proceeding versus the Transmission Owner at FERC.

Using modern inverters, wind and solar generators can exceed the requirements of Order 827 by providing reactive power service that is faster and more accurate than conventional generators, offering a broader range of voltage control, and even providing service when they are not producing real power – for instance, solar plants can stabilize voltage at night.[46] But without compensation they have no incentive to provide those services, particularly given the cost of consuming real power from the grid to provide reactive power.[47] If a standard compensation method were easily accessible, inverter-based resources could determine whether and when it is cost-effective for them to provide valuable reactive power to the grid, and bid such service into the RTO for scheduling.

Beyond the principle that every resource that provides a valuable service should be compensated for that value, compensation is critical for efficiently planning and dispatching the system to meet reactive power needs. If transmission owners are not required to compensate generators for providing reactive power, transmission owners will rely on uncompensated generation assets to support voltage rather than choosing solutions such as transmission upgrades and reactive power devices, that could be lower-cost for the system and customers overall. Because reactive power losses are significant over even moderate distances on the transmission system, it typically makes more sense to deploy a local solution where the reactive support is needed.

In a draft guideline, NERC has floated the idea of recommending that plants provide expanded service, but noted that compensation is critical.[48] However, a NERC standard request recently proposed by the California Independent System Operator would use mandatory requirements without compensation to obtain enhanced reactive power and other services from inverter-based resources, effectively penalizing these resources for their superior capabilities.[49]

To address reactive power compensation within PJM and MISO, it would be appropriate for FERC to issue a declaratory order or other generic rulemaking to standardize and streamline the process of filing for compensation for reactive power provision.

3.3.2 REMOVE BARRIERS TO RENEWABLE ENERGY PROVIDING OPERATING RESERVES LIKE FREQUENCY REGULATION. In PJM and MISO, as in other ISOs, market rules effectively prevent renewable resources and other

44 The AEP method compensates all generators (synchronous and non-synchronous) for the cost of providing reactive power service. For a summary of regional methods for compensating reactive power service, and potential improvements to the AEP methodology to allow more resources to participate, see FERC Staff (2014).

45 FERC (2016).

46 Loutan & Gevorgian, page 50.

47 One wind plant owner says that using the plant to provide reactive power when it was not producing real power increased the plant's parasitic load by a factor of 2.5 relative to not providing that service.

48 NERC (2018b).

49 See pages 678-692 at NERC (2018a).

advanced technologies from providing operating reserves including frequency regulation service. For example, MISO bars dispatchable renewables from providing frequency regulation, spinning reserves, and supplemental (non-spinning) reserves, though renewables can provide MISO's new ramping service.[50] Energy storage can provide frequency regulation but not the other reserves.

While some ISOs directly exclude renewable generators from providing frequency regulation, in others the barrier is a requirement that a resource be able to provide sustained regulation response over an extended period of time. That is not typically feasible for wind and solar generators, but if the service interval were shortened they could commit to providing the service with high confidence.

Beyond letting renewables provide frequency regulation services, there is potential value in establishing separate markets for up- and down-frequency regulation, because wind and solar typically face a greater opportunity cost for providing up-regulation than down-regulation.[51] Providing up-regulation ("reg-up") requires holding a plant below its maximum output at all times while it is offering the service so that it can increase output when needed to provide the reg-up service. In contrast, reducing the output of a plant to provide frequency down-regulation ("reg-down") only requires withholding the amount of output that is necessary to bring the system back into balance. Separate reg-up and reg-down markets could also enable greater regulation provision by storage resources, which at high or low levels of charge may be able to provide one service but not the other, and demand response resources (which typically can only provide reg-up service). This change could apply to both MISO and PJM.

Wind and solar plants, with wholly electronic controls, are able to provide regulation services with greater speed and accuracy than conventional power plants. CAISO has found that frequency

50 MISO Market Subcommittee (2016), page 4.

51 Up-regulation ("reg-up") entails quickly increasing generation to restore frequency to safe operating levels when load on the grid exceeds available generation (as when a large generator fails or transmission drops, cutting delivery from one or more power plants). Down-regulation ("reg-down") involves a fast drop in generation to restore frequency to safe operating levels when generation on the grid exceeds load (as when an extensive transmission or distribution event drops a large amount of load).

regulation from solar PV is around 90% accurate at meeting specific regulation demands quickly, which is almost twice as accurate as conventional generators and some energy storage technologies.[52] Even though wind and solar resources typically face higher opportunity costs than other resources for providing frequency regulation, their ability to offer premium products for fast and accurate response under FERC Order 755 can make them more economic for providing fast and precise response than conventional resources.[53] This change could significantly improve grid operational reliability.

Any changes to these market rules in PJM would require revisions to PJM Manual 11 and the PJM Tariff and Operating Agreement. MISO, unlike PJM, does not operate a "fast regulation" market, but only a slower market that does not reflect the full value of the faster service that renewables energy and renewables plus storage could provide. Any changes to MISO's regulation services will require revisions to the MISO Tariff and associated manuals.

3.3.3 PRIMARY FREQUENCY RESPONSE MARKETS. In Order 842 earlier this year, FERC declined to address compensation for providing primary frequency service,[54] leaving it up to RTOs to create markets or compensation mechanisms for the service.[55] Markets for primary frequency response should result in more economic operation of the power system because the cost of providing the service varies considerably across different resources and over time. The lack of compensation for primary frequency response is a primary reason why provision of the service has lagged, with NERC finding in 2012 that only 10% of conventional generators were providing sustained primary frequency response.[56]

RTOs should not require renewable resources to curtail production to reserve headroom to provide upward primary frequency response, as has been discussed in some PJM stakeholder meetings. FERC was clear in Order 842 that it was not imposing a headroom requirement, although that does not prevent an ISO from attempting to do so. Such a requirement would keep low-marginal cost resources like wind and solar from earning revenues on their full operational output and would likely be viewed by FERC as not just and reasonable and unduly discriminatory.

During a frequency disturbance requiring upward primary frequency response, resources should be allowed to increase their output above interconnection limits or dispatch limits imposed by thermal constraints on the transmission system. This allows resources that are curtailed due to transmission thermal limits to offer valuable upward primary frequency response at essentially zero opportunity cost, and there is no significant harm to the transmission system from exceeding thermal limits over the seconds-to-minutes timeframe for which primary frequency response is deployed.

Any changes to these market rules in PJM will require changes to the PJM Tariff and Operating Agreement, as well as PJM Manual 11. In MISO, changes to primary frequency response rules would affect the MISO Tariff and MISO Manual 018, among others.

3.3.4 RENEWABLES SHOULD BE ABLE TO PROVIDE AND SET PRICE FOR ALL RELIABILITY SERVICES. As noted above, most RTOs' rules do not permit renewable resources to provide reliability services like operating reserves. Many current RTO stakeholders do not understand or trust renewable generators' ability to provide reliability services, or assume that renewable resources will always produce the maximum output they can based on the solar or wind resource available at that time. Some operators may not feel comfortable with meteorological or forecast-based estimates of wind and solar plants' available capacity for operating reserve or ramping headroom.

Contractual barriers can also limit the participation of renewable resources in reliability services markets in the near term. Payment in most PPA contracts is based on MWh of energy delivered, which incents maximum generation without regard for the value or reliability need for reliability services. Depending on how the contract is structured and prevailing power prices at the time, curtailing energy output to provide reliability services can create a principal-agent problem between the party that wants to maximize energy production and the party that wants to earn revenue from selling reliability services. Even if using a renewable resource to provide frequency regulation could reduce that

52 Loutan & Gevorghian, p. 30.

53 FERC (2011).

54 FERC (2018).

55 There is currently no market for the provision of primary frequency response, which results in many generators failing to provide sustained primary frequency response. See, e.g., NERC (2012) pp. 32-33.

56 NERC (2012) p. 95.

renewable plant's curtailment relative to if the plant were not used to provide that service, one party may not want more generation from the plant if real-time power prices (and hence the economic value they receive for the energy) are below the PPA price. These challenges can be overcome as PPA structures evolve from simple volumetric rates based on a fixed payment for each MWh produced to designs that reflect the ability of renewable resources to provide reliability services.

3.3.5 CREATE ADDITIONAL FLEXIBILITY PRODUCTS. Market operators have tried several different approaches to procuring flexibility. MISO has reported success from its implementation of a 10-minute ahead Ramp Capability Product.[57] MISO assesses likely variability and uncertainty over the next 10 minutes and then procures enough flexibility to meet that need. MISO allows renewables and other resources but not storage to provide the service and has seen 95-97% of eligible resources participating. Pricing is based on a resource's opportunity cost, a ramp capability demand curve, and incentives for performance in following dispatch.

CAISO has tried a different approach to procuring capacity with its flexible resource adequacy criteria and must offer obligations (FRACMOO) program.[58] Under FRACMOO, utilities are required to demonstrate on an annual basis that they have enough flexible capacity to meet their contribution to the CAISO system's ramping needs, and the resources they use for compliance are required to then offer into the energy market. This is an addendum to the resource adequacy requirements that are imposed on the utilities, so it functions more like a capacity market product than a flexibility service product in that it is a forward procurement of a capability, not actual performance in providing a service. As a result, it has failed to efficiently incentivize the actual provision of flexibility,and CAISO is working on alternative approaches.[59]

Grid operators will likely continue to develop different types of flexibility products. Different resource configurations and load characteristics may require different speeds and durations of ramping. This would allow fast-acting but duration-limited resources, like renewable resources and some storage resources, to provide the services they can contribute.

MISO believes it could also benefit from more commitment of ramping capacity "look-ahead dispatch" in the 10 to 30 minute time frame to ensure adequate ramping capacity will be available. MISO is also considering committing flexibility up to a week ahead in order to schedule transmission outages better and provide generation outage guidance that ensures adequate flexibility remains available at all times. RTOs could use more extensive and accurate bid parameters to improve actual flexibility performance, with or without additional reliability services. But additional flexibility products are likely warranted to address and deliver better essential reliability and flexibility services including speed, charge, duration, etc.

Creating more flexibility products will require a sustained involvement at the RTOs to build consensus around the appropriate need for, characteristics and value of new flexibility products. This will require substantial changes to PJM and MISO's Tariff and manuals, and in general changes to its market rules and operational procedures.

3.3.6 MAKE CONTINGENCY RESERVES AVAILABLE TO ACCOMMODATE ABRUPT DROPS IN RENEWABLE OUTPUT. Contingency reserves are used to restore system supply and demand following the loss of a large conventional generator, typically with a mix of fast-acting spinning resources (faster than 10 minute response) and slower-responding non-spinning resources (less than 30 minute response). The cost of these reserves is currently allocated to load rather than generators, yet these reserves are activated only for conventional generator failures and not abrupt drops in renewable output. While renewable output generally changes gradually and predictably, at high penetrations a large unexpected drop-off in wind or solar output over a fraction of an hour can occur several times per year.[60] Because both conventional generator failures and renewable output drops occur so rarely, it likely does not make sense to hold separate reserves for each type of event. Grid operators should also examine the potential for demand response resources to provide contingency reserves, as ERCOT does today.

57 MISO Market Subcommittee (2016).
58 CAISO (2014).
59 CAISO (2018).
60 NREL (2010), p. 312.

3.4 CAPACITY MARKET REFORMS

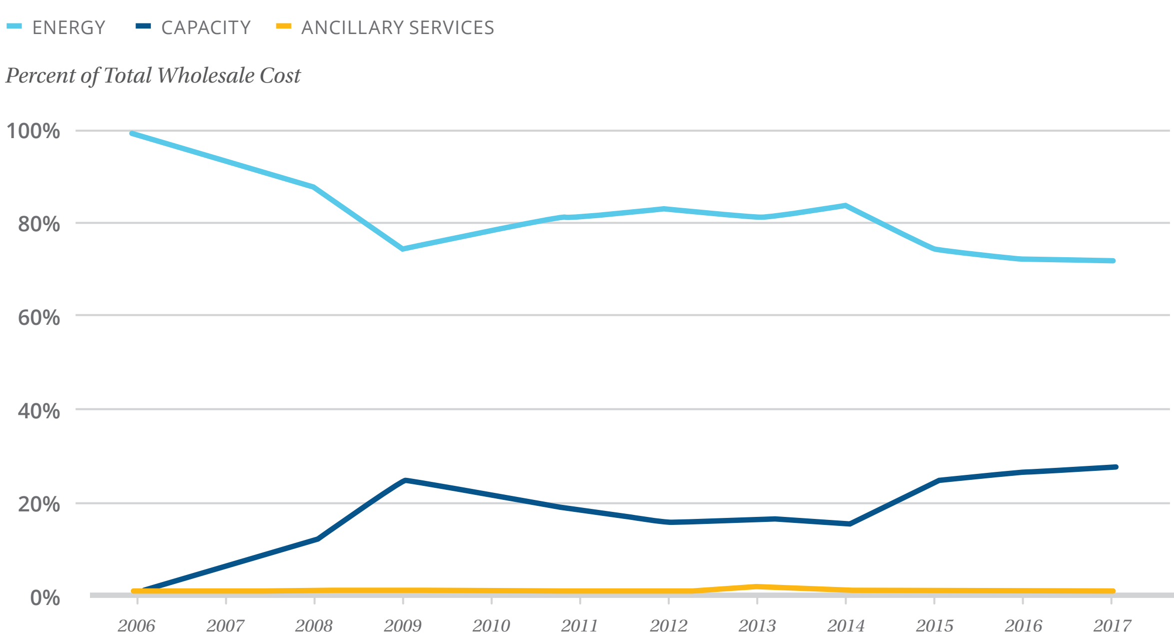
"Capacity" is defined as a separate product in each US RTO/ISO region except ERCOT. When a generator or demand resource sells capacity, it is generally committing to bid in the spot market if it is available at all times including at annual peak load, and to pay a penalty for non-performance. It can be viewed as a call option on a resource purchased by the grid operator on behalf of all load. Each Load-Serving Entity has an equal obligation to procure capacity based on their own contribution to peak load (the exact allocation is up to states and can vary) and thus pays a share of the system capacity requirement.

PJM and MISO differ greatly in how they treat capacity. MISO leaves resource adequacy to the states and uses a voluntary capacity market as one mechanism that states and utilities can use to acquire resources. MISO's capacity rules however have a significant influence on how states conduct Integrated Resource Planning because they aim to meet the capacity targets set by MISO. MISO is currently reviewing its capacity rules through its "Ensuring Resource Availability meets Need" process.[61] In PJM, the capacity market is mandatory (for almost all buyers and resources) and therefore has a much higher volume of transactions.

Capacity market design has been very problematic for renewable resources. In recent years PJM has imposed penalties for non-performance that exceed the benefit of selling the capacity, as well as requirements that resources be available year-round.[62] "Capacity" has never been a very well-defined term, which makes it subject to stakeholder influence, and the balance of stakeholder interests supports conventional resources rather than new technologies. Storage resources have been excluded from capacity markets due to unnecessary performance duration requirements. All such exclusions or limitations on participation have the effect of decreasing supply and raising costs for customers.

With decreasing wholesale market energy prices, capacity market revenues in PJM are making up an increasingly large percentage of total market revenues, as shown in Figure 6,[63] even though PJM has experienced a significant generation surplus over the past decade. This revenue shift reflects the fact that capacity prices have stayed relatively flat while energy prices have fallen due to declining natural gas prices and increasing low-cost renewables, flattening demand and reduced scarcity in the PJM market.

FIGURE 6. *Energy, capacity and reliability services as shares of total PJM market revenues*
(Source: PJM (2017), p.7)



61 Vannoy (2018).
62 See PJM Tariff, Attachment DD.
63 PJM (2017).

Wind and solar resources are given lower capacity ratings than conventional resources because wind and solar resources have variable generation patterns and wind, in particular, rarely produces at full capacity levels during hot summer afternoons when peak loads tend to occur. But capacity ratings methods (including linking capacity to peak load expectations and relying on historic performance averages for technologies experiencing rapid performance improvements) and capacity pricing terms have to date been structured in ways that are unfavorable for renewable resources. In recent years, many notable scarcity events involving significant generation shortages relative to load have occurred at non-peak times (such as the 2014 Polar Vortex and 2018 Bomb Cyclone winter events) wholly unrelated to forecast maximum peak load, and wind has performed well during those events.

Another concern is that capacity markets operate in such a way that they delay the retirement (market exit) of uneconomic conventional generation. This is partially because capacity market auctions reward promises of availability at peak load periods, and procure capacity three years in advance. In recent years demand growth has fallen short of projections (meaning that capacity needs were over-stated relative to actual loads) and actual economic conditions (such as natural gas prices and wind generation costs) changed markedly between the capacity auction and the date of use. Thus, PJM in particular has been paying for capacity that was uneconomic and sometimes unavailable when actual scarcity events occurred. In contrast to RTOs with mandatory capacity obligations, a large amount of coal capacity has recently retired in ERCOT's energy-only market because it did not have the economic support of capacity market payments and could not compete against lower-priced natural gas-fired and renewable generation.

We recommend several capacity market reforms below to improve reliability and efficiency in a high renewable energy future.

3.4.1 RESPECT STATE RESOURCE CHOICES. States continue to retain authority over their generation and resource mixes, despite state restructuring legislation. This authority is confirmed by the Federal Power Act. Energy industry investors are aware of the risk of future state policy changes, and that public policy risk is one that they bear. Yet in electricity, RTOs including PJM are actively interfering with state policy with Minimum Offer Price Rule (MOPR) restrictions.[64] These restrictions do not lead to just and reasonable rates for customers if some resources on the system are excluded from the market when determining prices, or prices are artificially raised through minimum bid requirements. We recommend that the application of MOPR to state Renewable Portfolio Standards (RPS) be minimized or avoided altogether, at least in the case where the resources were developed through competitive processes In competitive renewable procurements and markets with many sellers of Renewable Energy Certificates (RECs), the policy is clearly compatible with competitive markets.

In PJM, discussions are well underway to consider changes to the PJM Tariff, Attachment DD, with respect to the capacity market, as well as Schedule 8.1 of the RAA, and accompanying Manual provisions. FERC ruled that the current capacity market is unjust and unreasonable, and ordered a paper hearing for alternatives to be considered. A major component of that policy will be the application of MOPR.

MOPR does not apply in MISO and there are no active proposals to apply it.

3.4.2 ALLOW MOPR TO BE AVOIDED. In a recent order, FERC opened the door in PJM to allow loads and state-supported resources to contract bilaterally without the MOPR being applied. This is called the Resource-Specific Fixed Resource Requirement Alternative. The specific design is under debate in the stakeholder process. We recommend that LSEs and state-supported resources be given maximum flexibility to secure bilateral contracts outside the centralized market, and states be allowed to guide or direct purchases for entities under their jurisdiction. In the PJM Resource-Specific Fixed Resource Requirement Alternative, states should be allowed to guide or direct capacity purchases by LSEs under their jurisdiction. As noted above, all resources procured through bilateral contracts should participate in market dispatch, to assure grid reliability through centralized scheduling, dispatch and congestion management.

3.4.3 ENSURE CAPACITY MARKETS REFLECT RENEWABLE RESOURCES' TRUE CAPACITY VALUE. PJM is currently reevaluating its method for determining capacity ratings for various types of capacity resources, opening up active dispute over the correct capacity valuation method. PJM has proposed to reduce wind's capacity value from 13 percent to around 8 percent of nameplate capacity based on a crude methodology of median output during certain hours. The

64 MOPR is a minimum offer placed on certain resources selling into capacity markets. It was originally developed for resources procured by states. PJM and FERC have recently decided it should apply to resources that receive any form of state incentive.

proper way to determine capacity value is to perform an Effective Load Carrying Capability study, which determines the likelihood that a resource will be available at all times that it may be needed. MISO and PJM studies using the ELCC method have consistently shown capacity values for wind of 15-20 percent of nameplate capacity, and PJM's analysis calculated a capacity value of around 55-65 percent for solar.[65] ELCC studies should take account of the particular technologies entering the market because current model renewables have higher capacity values than past models at the same location, due to continued technology performance improvement.

Any changes to PJM's method for evaluating capacity will require extensive changes to PJM Manual 18, as well as associated provisions of the PJM Tariff, Attachment DD, among others.

3.4.4 RELAX THE REQUIREMENT FOR CAPACITY TO PERFORM YEAR-ROUND, AND CREATE SEASONAL RATHER THAN ANNUAL CAPACITY PRODUCTS. Current PJM rules require resources to perform year-round to earn the capacity payment, yet wind and solar and residential demand response have season-specific performance and availability capabilities. A more efficient market would establish separate summer and winter capacity products with associated capacity factor calculations and performance requirements. The MISO IMM has recommended this change for the MISO market as well, and the same principles apply to both PJM and MISO. The MISO IMM asserts the following benefits of this change:

- The revenues would be better aligned with the value of the capacity;
- Relatively high-cost resources would have an opportunity to achieve savings by taking seasonal outages during shoulder seasons;
- Resources retiring in mid-year would have more flexibility to retire then without having to procure significant replacement capacity to satisfy post-retirement capacity obligations in the remainder of the year;
- The qualification of resources with extended outages can better match their availability; and
- The duration of [System Support Resource] contracts can be matched with planning seasons, which removes a barrier for SSR Units to serve as Planning Resources.[66]

In PJM this change will require major changes to PJM's capacity market rules, as well as PJM Tariff, Attachment DD and PJM Manual 18.

3.4.5 ALLOW STORAGE PARTICIPATION IN CAPACITY MARKETS. Storage resources should be allowed to participate in capacity markets, to increase overall system operating flexibility. PJM is unique in requiring 10 hour performance tests to qualify for selling capacity — yet peaks tend to be much shorter than ten hours, and are getting shorter as solar serves most of the early afternoon and shifts system peaks to the late afternoon and early evening. Most batteries cannot deliver ten straight hours of full output, so they are effectively excluded from supplying capacity in PJM. MISO has a four-hour duration requirement. Duration requirements should be re-examined because shorter increments of flexibility provide reliability services more efficiently than longer increments.[67]

In PJM, this change will require changes to PJM's capacity market rules, as well as PJM Tariff, Attachment DD and PJM Manual 18.

MISO has a "Use Limited Resource" capacity product that allows a resource to be a capacity resource if it is capable of providing the energy equivalent of its claimed Capacity for a minimum of at least four (4) continuous hours each day across MISO's peak, and meets other requirements specified in MISO Manual No. 011. However, MISO also has rules in Manual 011 stating that battery storage resources are eligible to qualify as Planning Resources only if they are behind the meter. This is an unwarranted restriction; any storage or storage plus renewable resource that can meet the minimum 4-hour performance requirements should be considered as a capacity resource. Changes to these rules will require revisions to MISO's tariff and MISO Manual No. 011.

65 Falin (2016), page 29.

66 Potomac Economics (2018), pp 101-102.

67 Shorter requirements result in a much larger population of qualified resources, and thus more capability at lower cost. If long-duration ramp needs occur, they can still be met by combining shorter-duration blocks of flexibility, such as a fleet of one-hour batteries.

3.4.6 ENSURE CONVENTIONAL GENERATORS ARE NOT AWARDED EXCESS CREDIT RELATIVE TO RENEWABLE RESOURCES.[68] Many conventional generators face correlated risk of forced outages, as demonstrated in recent severe weather events and analysis of NERC data.[69] The logical response to this finding would be to decrease the capacity value awarded to conventional generators that experience correlated outages (as from coal plant inventory freezes or NRC-ordered nuclear shutdowns), just as correlated output patterns for wind and solar are used to calculate those resources' capacity values.

In PJM this change will require revisions to PJM's capacity market rules, as well as PJM Tariff, Attachment DD and PJM Manual 18.

In MISO, this revision will require changes to MISO's capacity market rules, as well as MISO's Tariff and MISO Manual 011.

3.4.7 EFFORTS TO ADD A FUEL SECURITY COMPONENT TO THE CAPACITY MARKET SHOULD BE ABANDONED UNLESS DEMONSTRATED TO IMPROVE RELIABILITY OR EFFICIENCY. PJM is undertaking a fuel security study process, which is expected to conclude in late 2018 or early 2019. PJM has indicated that the study is likely to result in proposed design changes to the capacity market. It is premature to pursue design changes absent a proven justification for why fuel security matters. There is no such thing as a "fuel secure resource" because every resource has limitations, whether from fuel availability, mechanical failure, or safety restrictions. Products should be defined by the service provided (eg, commitment to deliver energy during winter or summer peak conditions subject to penalty), not supply characteristics (eg, type of fuel). Forcing customers to pay for such a poorly defined product with questionable reliability value would lead to unjust and unreasonable rates.

3.4.8 REFORM THE CAPACITY PERFORMANCE PENALTY STRUCTURE TO BE SYMMETRIC. Currently there is more of a downside to under-performing, due to the existing penalty structure, than an upside (from the capacity payment plus energy scarcity pricing) to over-performing. For variable resources, this structure needs to be more symmetric for resources to be willing to participate.

In PJM this change will require changes to PJM's capacity market rules, as well as PJM Tariff, Attachment DD and PJM Manual 18.

3.4.9 ALLOW GENERATORS TO RETAIN THEIR CAPACITY INTERCONNECTION RIGHTS (CIRS) IF CAPACITY VALUES CHANGE. A wind or solar generator that interconnects to the grid is charged for network transmission upgrades according to its capacity value. The generator pays for this transmission and gets the ability to deliver without curtailment to the pool. Existing resources whose capacity values are reduced by the RTO then lose that amount of transmission service. Since they paid for it and caused the capacity expansion, they should be able to keep these rights and monetize the excess transmission capacity right as appropriate.

Changes to PJM CIRs will involve changes to PJM and MISO's planning processes, as well as capacity market rules, and will impact multiple provisions of both RTOs' tariffs and manuals. Any changes to CIR related rules will need to be initiated within each RTO's stakeholder processes.

3.4.10 ALLOW HYBRID PROJECTS FOR PURPOSES OF MEETING MARKET RULES. If ISOs fail to fix fundamental flaws in the market rules that make it advantageous to pair resources (such as solar with batteries or demand response with wind), there should be better opportunities for resource aggregation and pairing. Flawed market designs create incentives to pair resources. The bulk power system inherently aggregates all resources and achieves a higher capacity value and less variability than the sum of its parts because output deviations among generators are not perfectly correlated. In an ideal market, pairing would not provide additional value to the system, but under current market rules the synergistic capabilities offered from pairing creates more revenue for both resources than operation as stand-alone resources. Pairing improves efficiency if resources are being denied credit for their actual contributions to system capacity needs, such as due to the lack of seasonal markets and the asymmetric penalty structure in PJM, or overly penalized for their operational deviations, or simply not being directed to operate with other resources in a synergistic

68 This risk arises from recent political arguments over the value of on-site fuel to provide "fuel security" and whether such fuel assurance plays a meaningful role for system resilience.

69 Murphy et al. (2018).

manner. While the best solution is obviously fixing flawed market and operational rules, if that is not feasible then expanded opportunities for pairing may help renewable, storage, and demand response resources operate more with better system contributions and higher revenues than they might otherwise receive.

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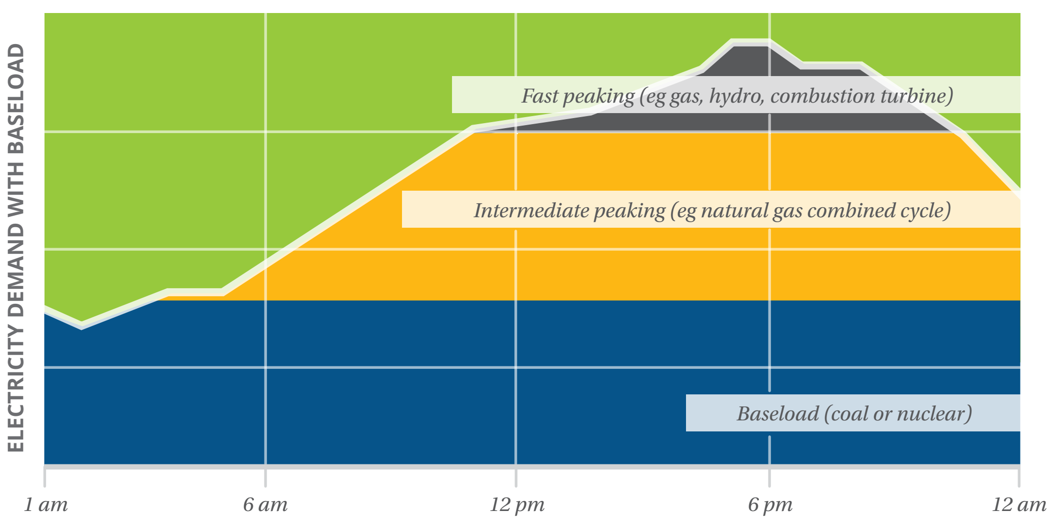
APPENDIX A

CURRENT POWER MARKETS WERE DESIGNED FOR THE PAST

Engineers design machines with the tools, constraints, and objectives they are given. Power system operation throughout the 20th century was designed to utilize the fossil, nuclear, and hydroelectric resources available, with the transmission grid as it was, to meet the existing load shape with the available operational tools. The basic problem was one of efficiently dispatching generators with different operating costs to meet forecasted demand, or "load." Load fluctuated over the course of the day and the season and there were certain generators that tended to serve the base load, intermediate load, and peak load. Demand moved slowly and predictably enough that relatively inflexible large nuclear units could be relied upon for much of the base load service, coal units could serve base load and some intermediate load by ramping up during the day, and simple cycle gas units and others that could be turned on and off served peak load. The historical correspondence between different types of generation and differing levels of highly predictable load is illustrated in Figure 3.

FIGURE A-3. *Historic correspondence between daily load patterns and types of generation*
(Source: Diesendorf (2016))



Many market features were designed around the characteristics of conventional generation units and grid needs in the 1990s, and technological limits on grid operators' monitoring, communications and analytical capabilities:

- The day-ahead unit commitment process (and later the day-ahead market) were designed to accommodate gas generators' need to procure fuel and the limited cycling capabilities of coal plants, which have limited ability to reduce their output during low-demand hours and generally require dozens of hours to shut down and then start up again.

- Make-whole payments were allocated to these committed resources because procuring sufficient capacity in the Day-Ahead timeframe was more important than the loss of flexibility from committing inflexible coal and nuclear generators.
- Energy and capacity revenue streams were generally separated to cover both the capacity and fuel cost of typical units, to meet the financial needs of both baseload and peaking units.
- Markets provided limited or no incentives for flexibility, particularly over hour-to-hour and longer periods, because both load and supply were generally predictable (other than contingency events from the loss of large conventional generators), so fast flexibility was rarely needed.
- Zonal Locational Marginal Prices (LMP) were intended to dispatch and encourage development of gas generation in transmission-constrained areas; these evolved to nodal LMPs in most regions as locational constraints became more prevalent and costly.
- Reliability services were provided by generators and defined by characteristics of the supply sources, such as "spinning reserves" and "inertia," rather than by the functional role that the service performed.
- Contingency reserves, primary frequency response, and frequency ride-through requirements were designed to keep the system stable following the loss of a large generator.
- Grid operators routinely held excessive levels of operating reserves, based on the expectation that inflexible resources would provide slow or inaccurate response when called upon to provide energy or operating reserves.
- Generators carried all responsibility for providing reliability services because customer loads were unmonitored and uncontrollable.
- Many reliability services, like primary frequency response and reactive power support, were not compensated because they could be provided by conventional generators at low cost and because the cost of providing them was covered by the rates paid by customers of vertically integrated utilities.
- Transmission and generation were scheduled well in advance of the operating period, because most of the available resources were relatively inflexible and the system lacked the fast communications and computing power to set schedules closer to the operating period.
- Generation and transmission were operated very conservatively using fixed operating limits and schedules and contingency analysis, because planners and operators lacked the ability to monitor and control power system operations and respond swiftly to contingency events in real time.
- Planners set up automated measures such as special protection systems, primary frequency response, and under-frequency load-shedding because they needed these to stop the spread of a potential system collapse and protect asset integrity in a time when grid communications and controls were slow and generator response capabilities were limited.
- There were few if any behind-the-meter resources for operators to account for.

APPENDIX B

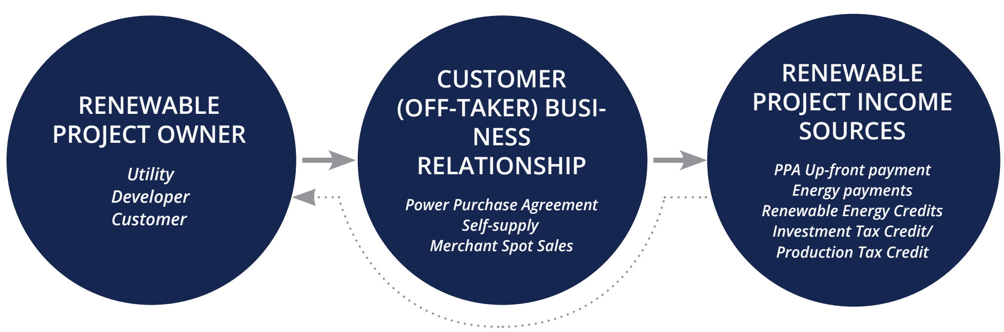
HOW AND WHY CUSTOMERS PURCHASE RENEWABLE ENERGY

This section reviews the ways in which utility-scale renewable energy is acquired and how that affects wholesale market design issues.

B.1 RENEWABLE ENERGY ACQUISITION OPTIONS

Figure B-1 illustrates the principal types of renewable project owners, their relationships with customers, and their revenue sources.

FIGURE B-1. *Renewable Project Owners, Relationships and Income Sources*



Most utility-scale renewable energy is sold through long-term power purchase agreements (PPAs) between off-takers (either regulated utilities, large corporate energy users, or competitive retail suppliers) and renewable project owners. Some projects are owned by utilities, which may self-develop or buy the project from developers.

Developers also sell environmental attributes of their generation, usually through Renewable Energy Certificates (RECs). While many buyers, particularly utilities, use RECs to comply with state Renewable Portfolio Standards (RPSs), many other buyers, in particular large corporate purchasers like Facebook, Amazon and Walmart, purchase RECs on a purely voluntary basis to meet their own corporate environmental and sustainability commitments. Sales of environmental attributes, energy, capacity, and reliability services can all be either bundled together in a single PPA or unbundled from each other and sold to different parties. Each revenue source is described below.

The most important driver of corporate and utility renewable energy acquisitions today is that renewable energy projects offer long term contracts (PPAs) for electricity at low prices that serve as a "hedge" against wholesale electricity market price volatility.[70] This allows corporate and industrial electricity customers to lock in long-term prices for electricity to better manage their businesses' costs and operations. Utilities can use renewable energy purchases to fulfill green energy tariffs and to hedge the utility's overall energy portfolio against wholesale electricity market volatility.

B.2 OVERVIEW OF PPA AGREEMENTS

Most of the revenue for renewable project owners comes through the PPA. Even where there is wholesale competition, generation developers use long-term PPAs to reduce risk and financing costs, which ultimately reduces the costs for consumers. Very few renewable projects are developed on a "merchant" basis (where sales are made on a short-term basis without any long-term commitment). Merchant plants typically have some type of financial hedge against energy price fluctuations.[71]

A PPA typically includes a fixed, pre-determined payment from the off-taker to the resource owner for each MWh generated. The energy is provided as it is generated (given that wind and solar production are intermittent and not dispatchable). PPAs are generally signed for a period of 20 to 30 years to line up with the projected life of the renewable project, though shorter-duration PPAs exist. Since wind and solar projects have relatively high capital costs and low on-going costs, long-term PPAs offer secure, contracted cash flows from a credit-worthy purchaser that cover revenues and return to enable construction financing.

In the past, almost all renewable PPAs were signed with utilities, which would use the generation to meet their customers' electricity needs and any RECs to meet RPS requirements. For the renewable generator, a utility PPA essentially transfers much of the risk of market-based revenue fluctuations to a utility with a diversified portfolio of resources, and many states allow the utility to pass that risk on to its customers.

Over the last five years many non-utility customers with large electricity demands have contracted directly with renewable plants. Large customers already experience significant risk from electricity price fluctuations, whether purchased through a utility or in direct energy purchases. The non-utility customer can manage that volatility by signing a long-term renewable PPA, because a wind or solar contract creates a predictable, low energy price stream over many years.

B.3 IMPORTANCE OF BASIS RISK

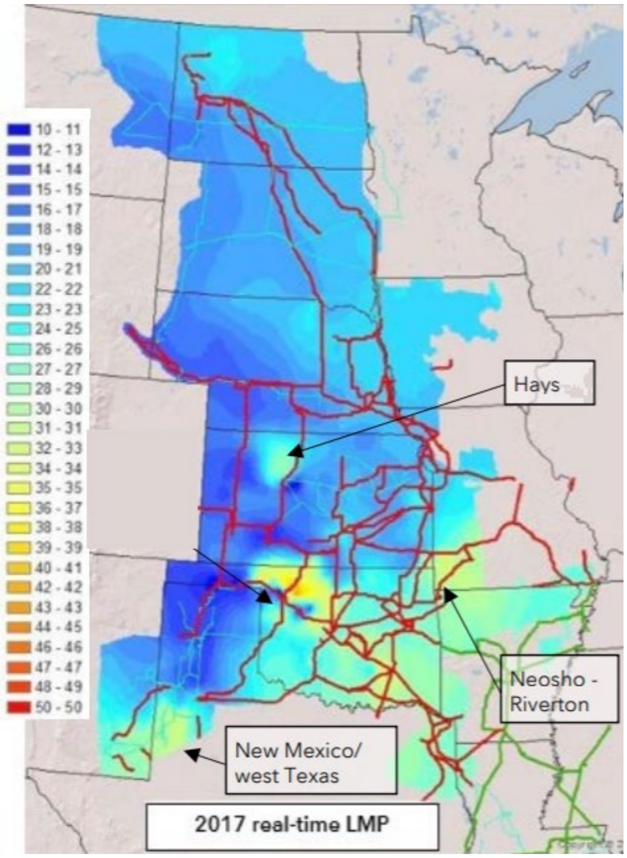
Wholesale energy market prices (Locational Marginal Prices (LMPs)) can fluctuate widely over time and across space due to the effects of differing resources in different locations and transmission congestion impeding the flow of electricity across the grid; where electrons flow on parallel paths according to the path of least resistance, one limiting element can lead to vastly different prices at different nodes and zones. This is particularly problematic for zero marginal cost resources like wind and solar, which can set power prices at zero or below when congestion occurs between where the plant is located and primary load centers. For example, in the LMP heat map below (Figure B-2), power prices in wind-heavy western SPP averaged $12/MWh in 2017 (blue area), half the SPP-wide average of $23/MWh (yellow and red area).

In the context of energy pricing, the LMP is called the "basis" price. The risk for the wholesale buyer and seller lies in how often and how much the basis price for contracted energy differs from its contract price. Congestion cost is the difference in LMP between the source and the sink. Congestion cost can be hard to predict, thus the term congestion risk. "Basis risk" or congestion risk is an increasing issue with PPAs, particularly for wind resources. Limited transmission capacity between the source (at the generator's node) and the sink (the load point) requires the party responsible for delivering the power to pay the congestion cost. Congestion risk can be hedged to some extent with financial transmission rights that can be purchased in RTO auctions. However, it is hard to know how much of this type

70 PPAs also protect against price volatility in retail electricity markets, although a discussion of the retail electricity markets is outside the scope of this report.

71 According to AWEA data, in MISO only 529 MW (3%) of the 17,980 MW of wind capacity installed to date are entirely merchant. In contrast, 25% (1,970 MW) of the 7,808 MW of wind capacity in PJM is purely merchant capacity; this reflects the facts that PJM has higher energy prices, more gas in the generation mix (so buyers use a wind contract to hedge against gas price fluctuations), and more states with high Renewable Portfolio Standard purchase requirements. As of 2015, the only merchant solar project in the U.S. was in ERCOT.

FIGURE B-2. *Example of Locational Market Prices in Southwest Power Pool*
(Source: SPP MMU (2017), p. 134)



of insurance to buy, and the term of the transmission rights are usually only a year or two, not nearly as long as the PPA or the life of the asset. The party responsible for delivering the power could be either the resource owner or the off-taker. In our interviews, off-takers expressed the view that basis/congestion risk is going to be largely shouldered by developers going forward; in contrast, in the past utility off-takers would include transmission of the renewable purchase in their own transmission service arrangements (and thus bear the congestion cost risk). Future PPAs will need to be structured for delivery assurance, with explicit considerations for generators to hedge congestion risk through the purchase of transmission rights.

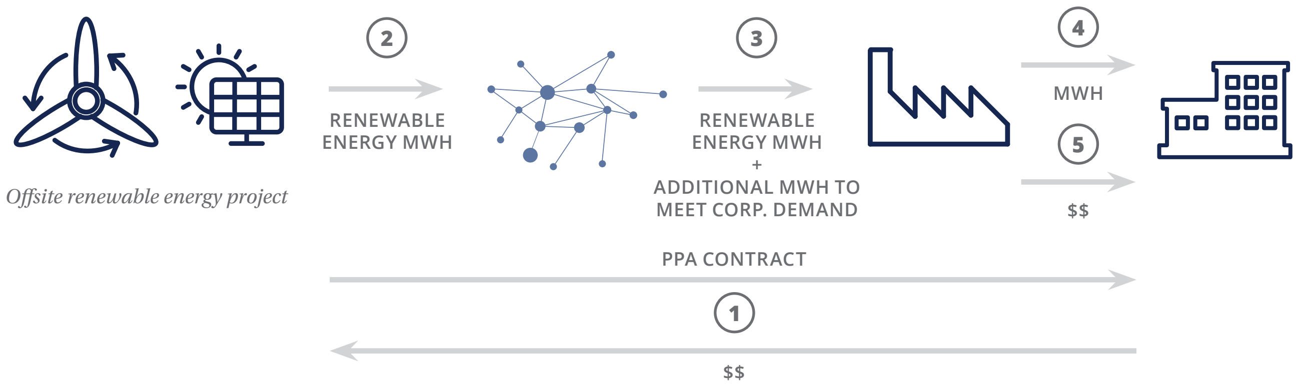
B.4 TYPES OF PPAS

There is a difference between "physical" (or "direct") and "financial" (or "virtual") PPAs. Physical PPAs are most commonly used by organizations with load concentrated at a single location (e.g., data centers, as opposed to commercial stores that are spread out over many locations). Under a physical PPA, the seller delivers renewable electricity to the "off-taker" (buyer), which takes legal title to the energy. Under a physical PPA, the final price for delivered power is a function of the contracted PPA price plus transmission-related expenses. In most cases, renewable energy acquired under a physical PPA is scheduled and dispatched through the RTO (although a few utilities might treat a PPA as self-supply).

In exchange for agreeing to off-take power for a fixed amount of time, physical PPA off-takers (such as large corporate buyers) lock in stable energy rates for the renewable energy purchased over the contract term, and typically gain title to RECs as part of the PPA. While physical PPAs are technically possible in traditionally regulated states with vertically integrated utilities, they are significantly more difficult to structure in such jurisdictions, meaning that most physical PPAs are executed in deregulated states. Figure B-3 illustrates how a physical PPA is structured:

FIGURE B-3. *Structure of a direct PPA between renewable generator and retail consumer* *(Source: Royal 2018)*

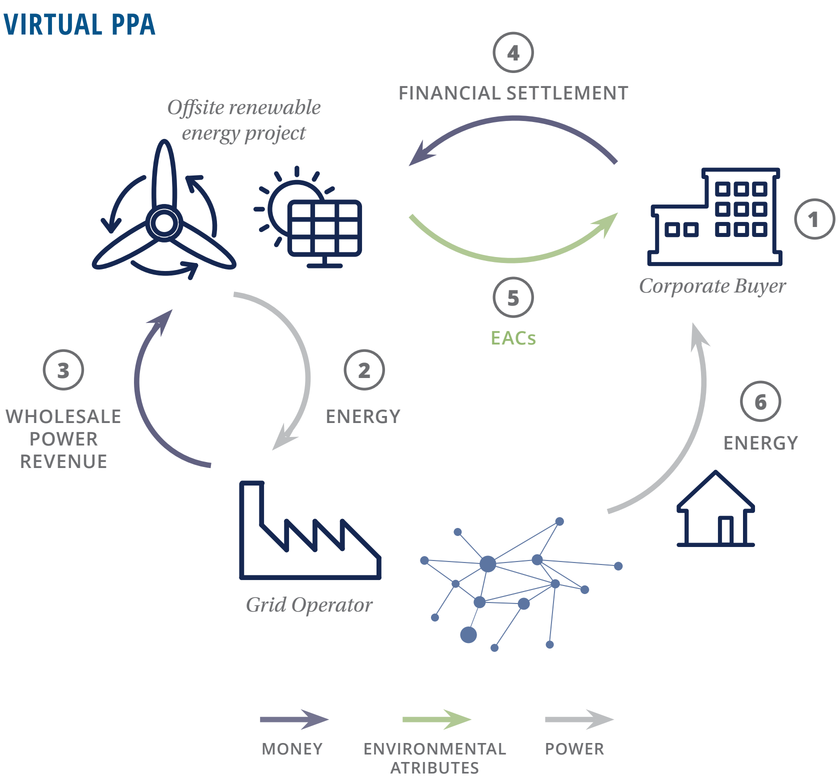
DIRECT RETAIL PPA



In contrast, under a virtual PPA, the buyer does not receive or take legal title to the electricity. Instead, a virtual PPA is *purely a financial contract* between the generator and buyer, where the buyer receives a varying revenue stream and the project's RECs. Consequently, instead of passing title for the power to the off-taker (as with a physical PPA), the generator sells its renewable power into the RTO energy market and receives the locational marginal price at the node where the generator is located.[72] The project developer pays the difference to the off-taker when the contract PPA price (strike price) is below the market price; and vice versa. In some cases the strike price is based on the market price at a major market hub. Unless the generator hedges this risk by buying transmission rights, this introduces basis risk for the difference in locational marginal prices between the hub and where the generation is injected. The buyer typically meets its electricity demand by buying wholesale power at the market node where its facility is located. As a result, unless transmission rights are contracted to hedge that risk, the buyer faces "basis" risk for the difference in LMPs between where the renewable generation purchase is settled and where it is consuming power.

Figure B-4 shows how a virtual PPA is configured with EACs (RECs) being sold from the renewable energy generator.

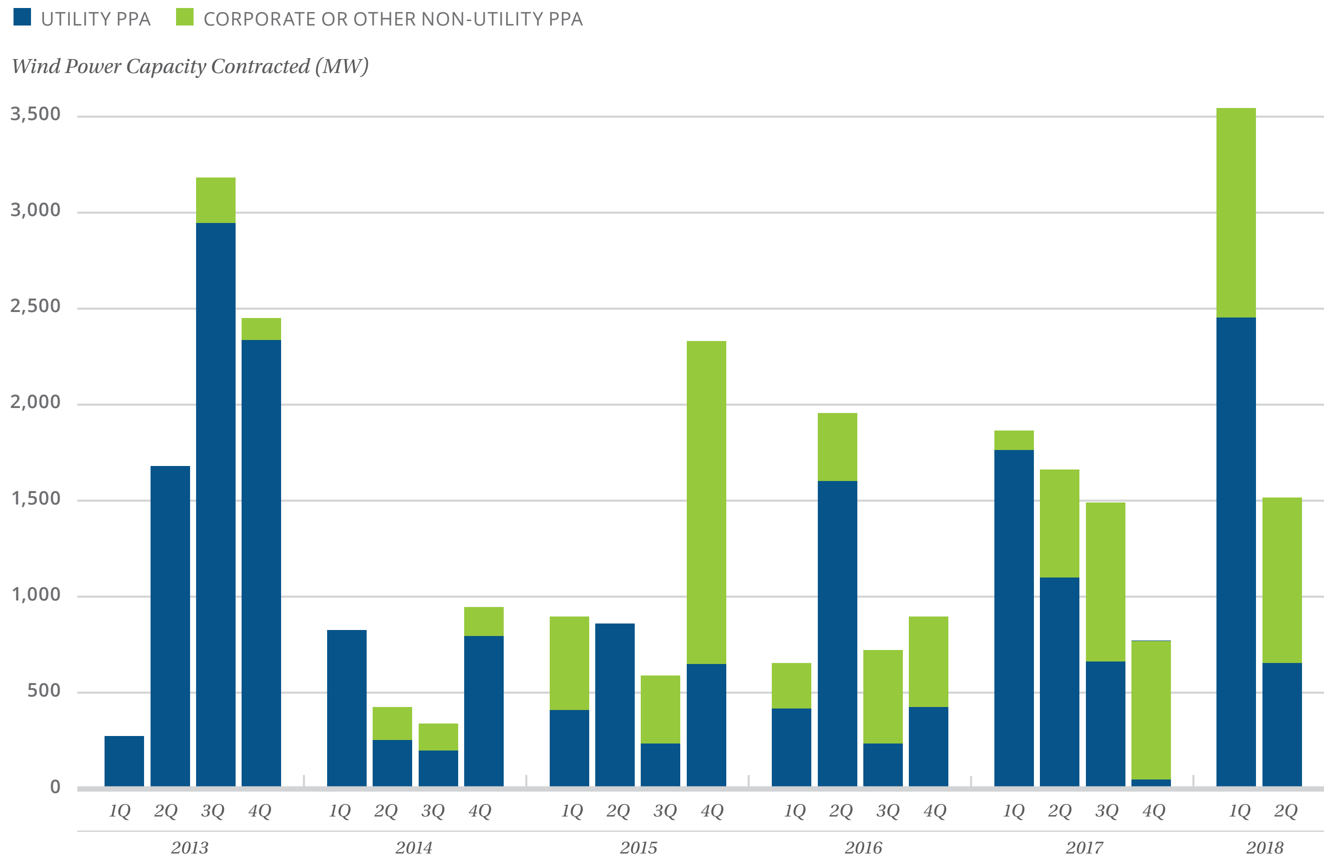
FIGURE B-4. *Structure of a Virtual PPA* *(Source: Royal 2018)*



Because a virtual PPA is merely a financial contract between a generator and off-taker, it enables off-takers located in regulated states or jurisdictions where they do not have access to open markets or renewable energy through their local utility to "go green" by entering into financial transactions where they do not have renewable power physically delivered to them, but still reap the benefits of renewable energy. For wind, non-utility PPAs are now almost as common as utility PPAs, as shown in Figure B-5.

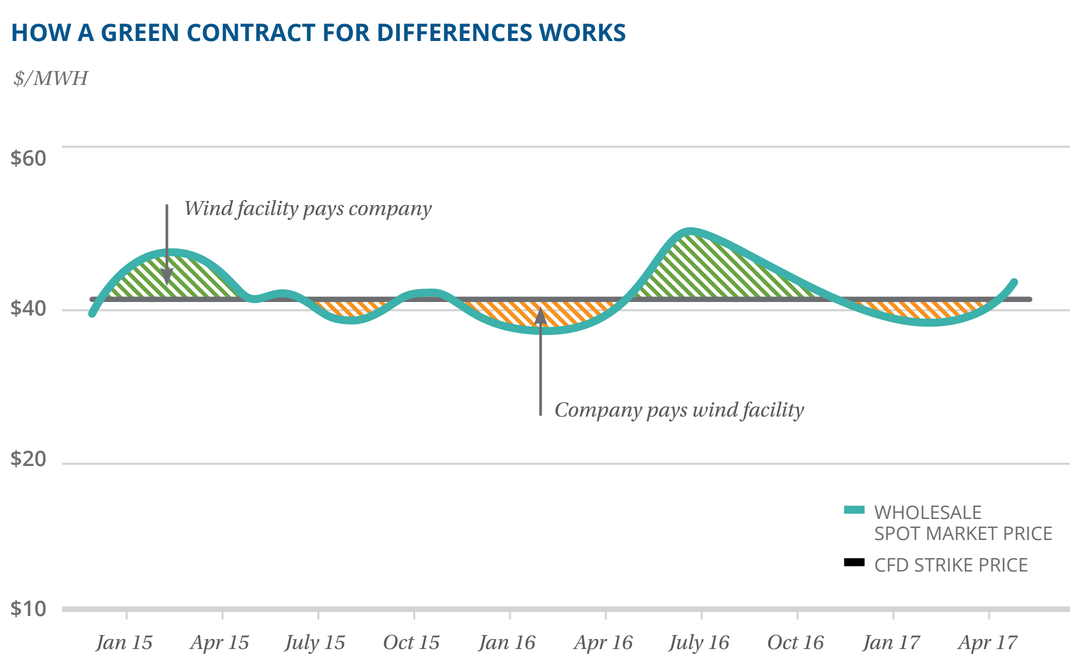
72 Renewable energy sold under a virtual PPA is scheduled and dispatched through the RTO.

FIGURE B-5. *Corporate PPAs now dominate wind contracts* *(Source: AWEA (2018))*



Aside from customer preferences for green power, the financial component of this structure — called a *contract for differences or a fixed-for-floating swap* — is often a significant motivator for corporate off-takers to engage in virtual PPAs. Figure B-6 illustrates how the payment stream under a contract for differences works:

FIGURE B-6. *The payment stream under a contract for differences (CFD)* *(Source: Johnson 2018)*



In most cases, PPA prices tend to be fixed price amounts and do not separate out capacity vs. reliability services vs. REC vs. energy payments (although there are some exceptions to that arrangement). Higher renewable penetrations tend to decrease the value of energy and increase the value of capacity and reliability services, which may drive increased customer attention to those value streams. On the other hand, carbon policy and transmission expansion will tend to increase energy market prices received by all generators, and the rents received by wind and solar generators.

Many utilities acquire renewable energy through traditional Integrated Resource Planning processes, which drive resource selection among competitive bids (ideally) that lead to PPAs. These jurisdictions offer much simpler contracting structures for renewable energy projects, and once an RFP is won, it is typically much easier for projects to obtain financing because the utility is often considered a safe and creditworthy off-taker.

B.5 RECS AND ENVIRONMENTAL ATTRIBUTES

The revenue provided by Renewable Energy Certificate (REC) sales is another important source of revenue for most renewable energy projects in the PJM and MISO regions. RECs compensate renewable energy resources such as solar and wind because of the “renewable” (i.e., pollution-free) environmental attributes of their power. RECs represent a separate revenue stream for renewable energy project developers distinct from wholesale electricity market revenue sources. RECs are associated with the renewable energy project actually producing electricity – each MWh of renewable energy produced is assigned a unique REC that turns the environmental attribute into a tradable element wholly separate from the actual physical energy. RECs are sold to buyers who “retire” the RECs to get credit for compliance with either state-mandated or voluntary goals. Historically, most RECs were acquired to fulfill state renewable portfolio standard requirements.[73] However, many consumers and large corporate entities now procure RECs to meet voluntary sustainability and corporate social responsibility goals.

REC markets tend to be highly volatile, which makes REC revenues a less stable and dependable revenue source that now contributes less to renewable energy project development.

73 Since RECs were used to comply with state obligations, most REC obligations were state-limited (i.e., compliance with a state RPS required retirement of RECs generated within that state).

APPENDIX C

MARKET STRUCTURE AND DESIGN PRIMER

C.1 MARKET STRUCTURE

"Market structure" refers to the organization of a market. The structure of an electric market can range from a monopoly with one seller (the utility) and many buyers (customers), an oligopoly (as with several generators selling to buyers) or free competition (where there are many buyers and sellers and no one is large enough to dominate the market). Market structure is important to achieve the flexible, fair, far, and free markets that are the most reliable and efficient with high penetrations of renewable energy.

Market structure has evolved differently in each region of the country. Until the 1990s almost all utility systems were vertically integrated, with each of the hundreds of utilities around the country owning generation, transmission, and distribution. Some were investor-owned, some owned by municipalities and other government entities, and some were customer-owned in the form of cooperatives. Since they were all monopolies, they were each regulated through public policy. Investor-owned utilities were regulated mainly by state public utility commissions with commissioners appointed by Governors or elected. Trading of electricity was limited to neighboring monopolies trading excess power in both long-term contracts and short-term deals.

Market structure began to change in the 1990s as the number of independent power producers grew, fueling the dramatic growth of wholesale power transactions. This was enabled by FERC mandating "open access" over the electric transmission system so that all parties would have equal access to deliver power across utility systems to distant buyers. During the same period, almost half of the states undertook "restructuring" to encourage various degrees of third-party generation, retail competition and unbundling of the utilities' generation from its wires functions. FERC further supported competition by creating "Independent System Operators" (ISOs) and "Regional Transmission Organizations" (RTOs) to provide non-discriminatory grid planning and operation, integrated "horizontally" over large geographic areas. For example, MISO was formed out of 26 separate Balancing Areas.

A map of RTOs is shown in Figure C-1. All RTOs perform the following functions:

- Region-wide economic balancing of load and generation using bid-based, security-constrained economic dispatch with locational prices (see market design discussion below);
- Procurement of short-term essential reliability services (frequency support, voltage support, and ramping/balancing) as well as short-term energy;
- Transmission operation and service provision; and
- Transmission planning (at least coordination).

In some cases, RTOs manage resource adequacy, ensuring there will be enough capacity installed to maintain the physical balance of load and generation several years in the future. They tend to do this through mandatory capacity obligations, with a central trading market, as discussed in Section 3.

FIGURE C-1. *Map of RTOs and ISOs in North America*

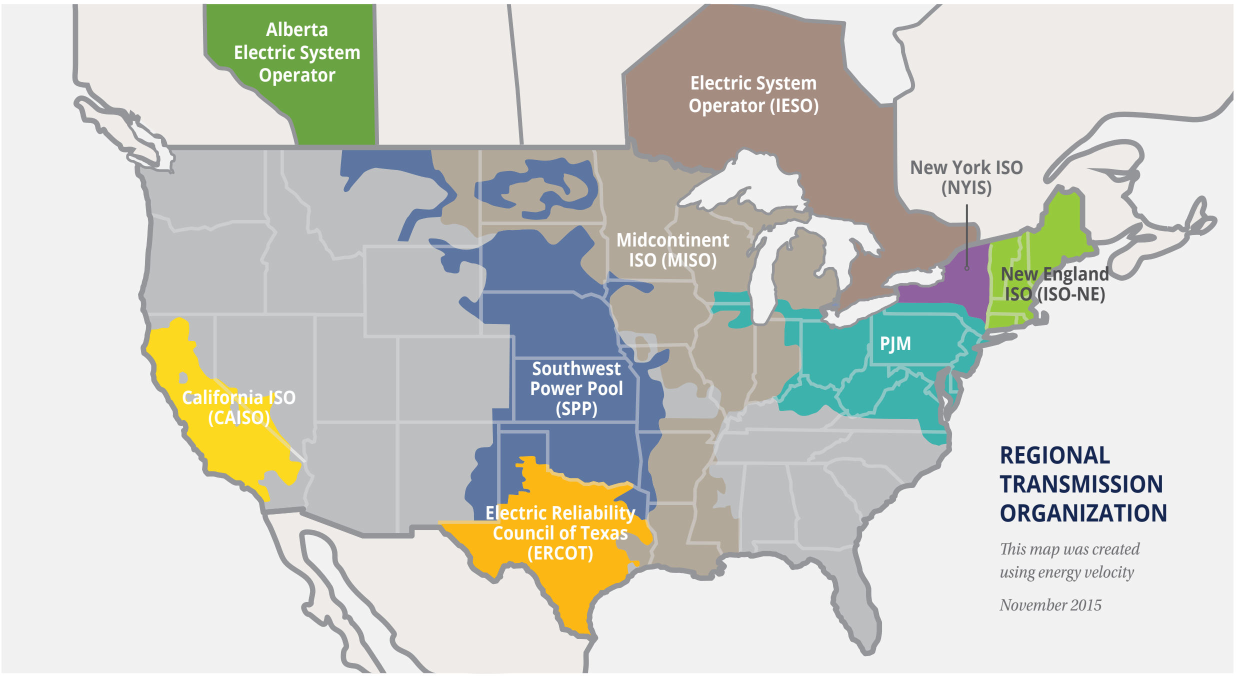


Table C-1 summarizes some of the dominant electric market features in each of these areas:

TABLE C-1. *Market Structures in the U.S.*

MARKET CHARACTERISTIC	VERTICALLY INTEGRATED, NO RTO/ISO	PREDOMINANTLY VERTICALLY INTEGRATED WITH RTO/ISO	PREDOMINANTLY RESTRUCTURED WITH RTO/ISO
REGIONS	Most of West, Southeast	MISO, SPP, parts of PJM and New England	PJM, New England, New York, ERCOT
GENERATION	Mostly utility-owned (self-supply), increasing numbers of third-party generators	Combination of utility-owned (self-supply), many third-party generators	Mostly third-party generation, a few utility-owned generators
LOAD ENTITIES	Vertically integrated utilities and transmission-dependent purchasers (e.g., distribution coops)	Vertically integrated utilities and transmission-dependent purchasers (e.g., distribution coops)	Retail electric providers including utilities acting as default retail providers; some Community Choice Aggregators and large industrial and commercial buyers
TYPES OF TRANSACTIONS	• Self-supply • Bilateral long-term contracts (PPAs) with other utilities and merchant generators • Bilateral spot market purchases	• Self-supply • Bilateral long-term contracts with other utilities and merchant generators • Spot market purchases through RTO-operated centralized wholesale market	• Bilateral long-term contracts with merchant generators • Spot market purchases through RTO-operated centralized wholesale market • Capacity market

C.2 MARKET DESIGN

"Market design" refers to the rules and mechanics of balancing generation and load, and the formation of prices for energy and the other services needed for reliable system operation.

Each RTO or ISO uses a common core market design called, "bid-based security-constrained economic dispatch with locational prices." This design evolved from the economic dispatch system used by vertically integrated utilities throughout the 20th century. Economic dispatch involved ordering generators with different operating costs in merit order from lowest cost to highest cost and dispatching them as load increased and decreased. "Security-constrained economic dispatch" (SCED) evolved to respect the transmission grid's physical constraints, which could necessitate dispatching generation inside of a binding transmission constraint rather than a less expensive generator outside the constraint. When markets were established, system operators modified their software to replace operating cost data with bids provided by generators — "bid-based security constrained economic dispatch." Finally, to provide a price signal for managing transmission limitations, "congestion pricing" was put in place in the form of "Locational Marginal Prices" (LMP). CAISO, PJM, ERCOT, MISO, SPP, NYISO, and ISO-NE all use this bid-based, SCED LMP core market design.

The other important element affecting market design and efficiency is the size and scope of the market. In the days of vertically integrated utilities dispatching their own generation, with limited intra- and inter-regional backbone transmission, there were few opportunities for utilities to take advantage of less expensive generation options offered in neighboring regions. But as FERC established open access transmission and wholesale market competition principles, the agency also encouraged the construction of new transmission and the expansion of RTO/ISO and market areas, to include more and more generation and load zones. Regional markets with more buyers and sellers and more deliverability options offer more trade opportunities, are much more competitive, and tend to yield lower costs for all consumers in the market.

The core market design is much more reliable, efficient, and conducive to variable resource integration than the system in place in the West and before ISOs and RTOs were in place.

APPENDIX D

RELIABILITY SERVICES PROVIDED BY RENEWABLE AND OTHER RESOURCES

The following table lists the primary essential reliability services identified by NERC and discussed in the reliability services recommendations in Section 3 of this report. The table uses written descriptions and red, yellow, and green to indicate the capabilities of different resources to provide those services, with green being the highest capability. Inverter-based resources have significant capabilities to provide these services:

The inverters in wind and solar power plants allow them to provide reactive power,[74] and can be designed to do so even when the plants are not producing power.

The inverters that electrically separate wind and solar resources from the grid allow them to "ride through" these disturbances better than conventional power plants that are directly synchronized to the power system (assuming they have been programmed to do so). As a result, since 2005 wind generators have met a more stringent standard for voltage and frequency ride-through than other generators.

Conventional power plants provide both inertia (from the rotating mass of the generator and the connected turbine, which continue rotating at the same speed even as grid frequency slows, and therefore can help stabilize the grid for a period of seconds) and slow primary frequency response. While wind and solar generators do not provide inertia, their inverters and other controls can be programmed to provide very fast primary frequency response that fulfills the same role as inertia in quickly stabilizing system frequency (assuming plant output was being curtailed and therefore can be increased by releasing the curtailment). ERCOT uses wind curtailment to respond when system frequency is high because such curtailment delivers a fast and accurate response, and wind now provides almost all of this response. Curtailment for high frequency response typically lasts seconds to minutes, so this does not come at a high cost to either the wind units or the market. In contrast, holding a wind or solar plant below its potential output so that it has capability to ramp up in response to a low frequency event requires being constantly curtailed, so that is seldom economic.

Wind and solar plant output can be dispatched up and down to meet ramping needs or frequency regulation, though curtailing low-marginal-cost energy sources to provide this service is often more expensive than reducing the output of power plants with higher fuel costs. Xcel does dispatch wind to regulate frequency in Colorado, particularly during hours when wind would have been curtailed anyway, and RTOs like MISO treat renewables as dispatchable resources.

74 FERC Order No. 827 in 2016 requires all new non-synchronous utility-scale generators to provide reactive power at levels comparable to conventional generators. However, many older inverter-based resources were not required to provide these services and were not compensated if they did provide the services, so the older plant inverters have not been reprogrammed to deliver reactive power and cannot be used for voltage management.

Essential Reliability Services provided by different generation technologies

(Source: Silverstein, Gramlich & Goggin (2018), Appendix B)

RELIABILITY SERVICE	WIND	SOLAR PV	DEMAND RESPONSE	BATTERY STORAGE	GAS	COAL	NUCLEAR
Voltage support: Reactive power and voltage control	Provides, and can provide while not generating by using power electronics.	Provides, and can provide while not generating by using power electronics.	Could provide, though this would require detailed knowledge of distribution system state and dispatch	Power electronics provide fast and accurate response	Must be generating to provide	Must be generating to provide	Must be generating to provide
Voltage support: Voltage and frequency disturbance ride-through (also important for frequency support)	Voltage and frequency ride-through capabilities due to power electronics isolating generator from grid disturbances. Wind meets more rigorous ride-through requirement (FERC Order 661A) than other generators.	Can thanks to power electronics, but standards have prevented use of capability	NA	Power electronics isolate battery from grid disturbances	Generators often taken offline by grid disturbances.	Generators and essential plant equipment, like pumps and conveyor belts, often taken offline by grid disturbances.	Generators and essential plant equipment, like pumps, often taken offline by grid disturbances.
Frequency support: Frequency stabilization following a disturbance (through primary frequency response and inertial response to disturbances)	Wind regularly provides fast and accurate PFR in ERCOT today. Can be economic to provide upward response if curtailed. Can provide fast power injection (synthetic inertia) if economic to do so.	Can provide downward frequency response today, can provide upward frequency response and fast power injection if curtailed.	Load resources currently provide this in ERCOT through autonomous controls when frequency drops below a certain point	Power electronics provide very fast and accurate power injection following a disturbance	Only 10% of conventional generators provide sustained primary frequency response	Only 10% of conventional generators provide sustained primary frequency response	Nuclear plants are exempted from providing frequency response, but they do provide inertia.
Ramping and balancing: Frequency regulation	Fast and accurate response. Can provide but often costly, particularly for upward response. Provides on Xcel's system.	Fast and accurate response. Can provide but often costly, particularly for upward response.	Autonomous loads like water heaters can provide, though the cost of disruption may be too great for other DR	Very fast and accurate response	Must be generating to provide	MISO data show a large share of coal plants provide inaccurate regulation response	Does not provide
Ramping and balancing: Dispatchability / Flexibility / Ramping	Fast and accurate response. Can but often costly, particularly for upward response. Provides on Xcel's system.	Fast and accurate response. Can provide but often costly, particularly for upward response.	Many forms of DR are likely to be energy limited or too expensive for longer duration deployment	Many types of batteries will be energy limited for longer-duration events, particularly if state of charge is not optimal going into event	Most gas generators are operated flexibly	Many coal plants have limited flexibility, with slow ramp rates, high minimum generation levels, and lengthy start-up and shut down periods	Almost never provides
Ramping and balancing: Peak energy, winter (color reflects risk of common mode unavailability reducing fleetwide output below accredited capacity value)	Wind plants typically have high output during periods of extreme cold, as seen in ERCOT in 2011 and much of the country in 2014.	Solar plants have lower output during the winter.	Many DR programs are not currently designed for winter peak demand reduction	Good, though will be energy limited for longer-duration events	High gas demand can cause low gas system pressure, fuel shortages. Can be mitigated with dual fuel capability or firm pipeline contracts.	Many coal plants failed due to cold in ERCOT in February 2011, polar vortex event in 2014, and other events.	Some failures due to extreme cold.
Ramping and balancing: Peak energy, summer (color reflects risk of common mode unavailability reducing fleetwide output below accredited capacity value)	In many regions wind output is lower during hot summer days, though that is accounted for when calculating wind's capacity value. In some regions, like coastal areas or mountain passes, wind output is higher on hot summer days.	Solar plants typically have high output on hot summer days, though solar output has typically declined by the early evening peak demand period.	Many forms of DR are used for summer peak load reduction today, including air conditioning curtailment	Good, though will be energy limited for longer-duration events	Gas generators experience large output de-rates when air temperatures are high.	Coal plants experience de-rates when cooling water temperatures are high.	Nuclear plants experience de-rates when cooling water temperatures are high.

HIGH CAPABILITY TO PROVIDE SERVICES | SOME CAPABILITY TO PROVIDE SERVICES | LITTLE TO NO CAPABILITY TO PROVIDE SERVICES

APPENDIX E

FERC'S AUTHORITY AND PROCESSES FOR CHANGING MARKET RULES

As this report discusses reforms to wholesale electricity markets, nearly all market reforms recommended in Section 3 are entirely within FERC's jurisdiction, and would not require any action by state authorities to implement. The only exception to this general rule relates to the potential capacity market reforms.

Given that FERC has the legal authority to unilaterally approve the vast majority of changes recommended herein, it is important to understand how the different recommendations discussed in this report can ultimately be implemented. These are summarized below.

RTO STAKEHOLDERS REACH CONSENSUS AND RECOMMEND CHANGES TO RTO TARIFFS THAT ARE FILED WITH FERC UNDER SECTION 205 OF THE FEDERAL POWER ACT (FPA). FERC approves these changes if they are deemed to be "just and reasonable." This is the process by which the vast majority of changes to RTO rules occur, so stakeholders who support the reforms outlined here should start by engaging in RTO stakeholder processes to advocate for these changes. Note that rule changes which only require changes to RTO manuals (i.e., do not involve a change to the FERC-approved tariff), RTOs seek stakeholder consensus and FERC approval is not necessary.

RTO STAKEHOLDERS FAIL TO REACH CONSENSUS ON PROPOSED CHANGES TO RTO TARIFFS, AND THE RTO FILES CHANGES WITH FERC UNDER SECTION 206 OF THE FPA. FERC approves these changes if the RTO proves that its current rules have become unjust, unreasonable and unduly discriminatory, and that the proposed changes are just and reasonable.

FERC ACCEPTS MOST TARIFF CHANGES PROPOSED BY THE RTO UNDER SECTION 205 OR 206 OF THE FPA BUT ORDERS CERTAIN REVISIONS. The RTO will submit those changes in a compliance filing to FERC. Note that FERC's recent decision in — NRG — significantly reduced the scope of changes that can be ordered through a compliance filing.

FERC REJECTS TARIFF FILING MADE BY RTO UNDER SECTION 205 OR 206 BUT DETERMINES THAT CURRENT RTO RULES ARE UNJUST AND UNREASONABLE. FERC, acting on its own authority, orders the RTO to submit a compliance filing implementing new rules that FERC has determined to be just and reasonable. In more complex matters, after FERC has determined that a current set of rules is unjust and unreasonable, the agency can order supplementary proceedings (which could include a technical conference, paper hearing, or other options) to gather additional information to enable the determination of new rules that are just and reasonable. FERC then issues a final order directing the RTO to implement new rules deemed just and reasonable. This process is currently underway with respect to the redesign of PJM's capacity market .

FERC INSTITUTES A SECTION 206 PROCEEDING ON ITS OWN AFTER DETERMINING THAT A GIVEN SET OF RULES IS UNJUST AND UNREASONABLE. This is typically preceded by some controversy (such as a complaint from one or more parties) that brings an issue to FERC's attention. A FERC-initiated Section 206 proceeding typically involves some sort of proceedings where parties are allowed to create a record on a particular topic, and normally ends with FERC directing

RTOs to implement certain changes. A high profile example of this occurring recently is the ongoing proceeding related to the redesign of PJM's capacity market.

FERC ISSUES A NOTICE OF PROPOSED RULEMAKING ("NOPR"), WHERE IT PROPOSES A GENERALLY APPLICABLE SET OF RULES. A typical NOPR will be broad in scope and apply to multiple RTOs. To develop the proposed rule, FERC usually holds one or more technical conferences on the matter to develop a robust record, building on witnesses' views with additional opportunities for post-technical conference comments submitted by interested parties. After NOPR issuance and consideration of comments, FERC issues a Final Rule with directives to RTOs to work with their stakeholders on developing RTO-specific compliance filings that will implement the Final Rule, and orders the RTOs to file associated compliance filings at a later date. Order No. 841, which creates additional opportunities for energy storage in wholesale electric markets, followed this general process.

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