FUTURE ELECTRIC
Utility Regulation

THE FUTURE OF CENTRALLY-ORGANIZED WHOLESALE ELECTRICITY MARKETS

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2. *Distribution Systems in a High Distributed Energy Resources Future: Planning, Market Design, Operation and Oversight* (October 2015)
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6. *The Future of Electricity Resource Planning* (September 2016)

Reports and webinar materials are available at **feur.lbl.gov**. Additional reports are underway.

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Foreword by U.S. Department of Energy

The provision of electricity in the United States is undergoing significant changes for a number of reasons. The implications are unclear.

The current level of discussion and debate surrounding these changes is similar in magnitude to the discussion and debate in the 1990s on the then-major issue of electric industry restructuring, both at the wholesale and retail level. While today's issues are different, the scale of the discussion, the potential for major changes, and the lack of clarity related to implications are similar. The U.S. Department of Energy (DOE) played a useful role by sponsoring a series of in-depth papers on a variety of issues being discussed at that time. Topics and authors were selected to showcase diverse positions on the issues to inform the ongoing discussion and debate, without driving an outcome.

Today's discussions have largely arisen from a range of challenges and opportunities created by new and improved technologies, changing customer and societal expectations and needs, and structural changes in the electric industry. Some technologies are at the wholesale (bulk power) level, some at the retail (distribution) level, and some blur the line between the two. Some technologies are ready for deployment or are already being deployed, while the future availability of others may be uncertain. Other key factors driving current discussions include continued low load growth in many regions and changing state and federal policies and regulations. Issues evolving or outstanding from electric industry changes of the 1990s also are part of the current discussion and debate.

To provide future reliable and affordable electricity, power sector regulatory approaches may require reconsideration and adaptation to change. Historically, major changes in the electricity industry often came with changes in regulation at the local, state or federal levels.

DOE is funding a series of reports, of which this is a part, reflecting different and sometimes opposing positions on issues surrounding the future of regulation of electric utilities. DOE hopes this series of reports will help better inform discussions underway and decisions by public stakeholders, including regulators and policymakers, as well as industry.

The topics for these papers were chosen with the assistance of a group of recognized subject matter experts. This advisory group, which includes state regulators, utilities, stakeholders and academia, works closely with DOE and Lawrence Berkeley National Laboratory (Berkeley Lab) to identify key issues for consideration in discussion and debate.

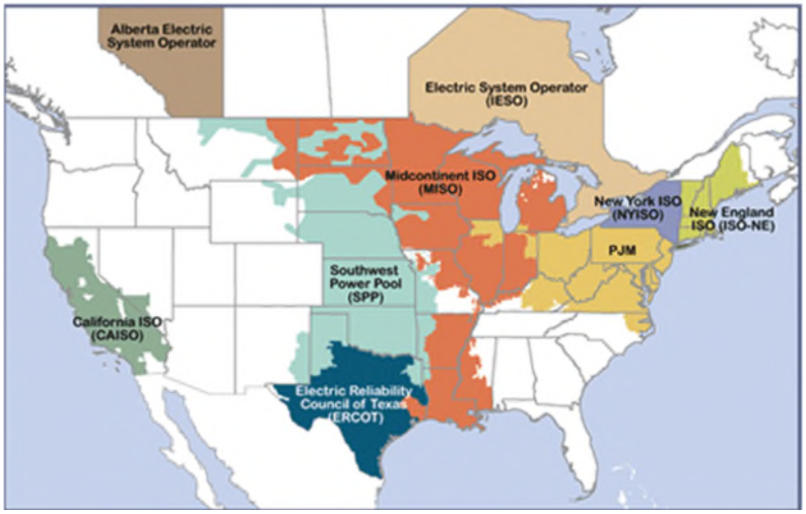
The views and opinions expressed in this report are solely those of the authors and do not reflect those of the United States Government, or any agency thereof, or The Regents of the University of California.

Introduction

The electricity grid in the United States is organized around a network of large, centralized power plants and high voltage transmission lines that transport electricity, sometimes over large distances, before it is delivered to the customer through a local distribution grid. This network of centralized generation and high voltage transmission lines is called the "bulk power system."

Costs relating to bulk power generation typically account for more than half of a customer's electric bill.[1] For this reason, the structure and functioning of wholesale electricity markets have major impacts on costs and economic value for consumers, as well as energy security and national security.

Diverse arrangements for bulk power wholesale markets have evolved over the last several decades. The Southeast and Western United States outside of California have a "bilateral-based" bulk power system where market participants enter into long-term bilateral agreements — using competitive procurements through power marketers, direct arrangements among utilities or with other generation owners, and auctions and exchanges.



North American RTOs and ISOs.[2]

Seven other areas of the United States have regional transmission operators or independent system operators (RTOs/ISOs) that administer centrally-organized wholesale electricity markets (see map). These markets operate at day-ahead, same-day and real-time time scales for energy trades, each playing an important role in reliably operating and economically optimizing regional grids and ultimately delivering electricity to consumers. Aspects of the bilateral model exist in

[1] Pennsylvania Public Utilities Commission. "Electric Bill Breakdown: Understanding Your Electric Bill." http://www.puc.state.pa.us/general/consumer_ed/pdf/Electric_Bill_Breakdown_FS.pdf.
[2] From FERC. Regional Transmission Organizations (RTO)/Independent System Operators (ISO). https://www.ferc.gov/industries/electric/indus-act/rto.asp.

RTO/ISO regions as well, particularly in the Southwest Power Pool and Midcontinent Independent System Operator. RTOs/ISOs also operate ancillary services markets to help ensure reliability, and three regions use a mandatory capacity markets approach to ensure adequate resources up to three years in the future.

Relevant FERC dockets,[3] meetings of the National Association of Regulatory Utility Commissioners,[4] and discussions at stakeholder engagement meetings[5] — as well as a markets technical workshop[6] for the U.S. Department of Energy's Second Installment of the Quadrennial Energy Review (on electricity) — all suggest that the bulk power landscape in the United States is functioning reasonably well, despite its enormous complexity, diversity and multiple challenges. However, the same record indicates that bulk power markets, particularly aspects of the RTO/ISO markets, remain a work in progress and in some cases the subject of continued debate. Much of the debate concerns the functioning of these markets in the long term.

This report presents differing viewpoints on four major long-term issues concerning RTOs/ISOs which lack a consensus:

1. Are today's centrally-organized market designs adequate to accommodate state public policy goals, and what potential design changes would further enable deployment of resources that achieve the goals of reliability, affordability and resource mix?
2. What are the market impacts of environmental regulations further constraining the deployment of fossil fuel resources?
3. What are the market impacts of integrating increasingly higher levels of renewable resources with zero marginal cost?
4. Are today's market designs adequate to acquire the flexible resources needed to better integrate increasing levels of variable energy resources at least cost?

Authors representing a variety of perspectives provide their responses:

- *Market operator* – PJM (Chapter 1)
- *Utility* – National Rural Electric Cooperative Association (Chapter 2)
- *Environmentalist* – Natural Resources Defense Council (Chapter 3)
- *Consumer* – National Association of State Utility Consumer Advocates (Chapter 4)

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[3] Federal Energy Regulatory Commission. Docket No. AD13-7-000: Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, and Docket No. AD14-14-000: Price Formation in Organized Wholesale Electricity Markets.

[4] NARUC. Meetings Overview. https://www.naruc.org/meetings-and-events/meetings-overview/.

[5] Quadrennial Energy Review Stakeholder Engagement. http://www.energy.gov/epsa/quadrennial-energy-review-stakeholder-engagement.

[6] Fox-Penner, Peter, Courtney Guard, and Rachel Eckles. The Boston University Institute for Sustainable Energy. *Bulk Power Markets in the United States: Challenges and Recommendations.* Report to the U.S. Department of Energy, Office of Energy Policy and Systems Analysis, June 17, 2016. Also see Bushnell, James, Michaela Flagg, and Erin Mansur. *Capacity Markets at a Crossroads.* Report to the U.S. Department of Energy, Office of Energy Policy and Systems Analysis. 2017. https://www.energy.gov/epsa/qer-second-installment-document-library.

1. A Market Operator's Perspective

By Craig Glazer, PJM[7]

Introduction

The electric sector is experiencing a rapid changeover of the generation fleet from one largely dependent on large central-station fossil units (principally coal) to a new, more diverse fleet consisting of a mix of renewable resources, demand response, distributed generation and efficient combined-cycle natural gas units. The pace of this changeover is truly stunning. Traditionally, changes to the profile of the generating fleet occur over decades given the capital-intensive, risk-averse nature of the industry. But due to the advent of shale gas and increased environmental restrictions, that changeover is occurring in a matter of a few years. As a result, it is an appropriate time to examine whether the nation's centrally-organized wholesale electricity markets need either a "tune-up" or a "make-over" in order to respond to this rapid pace of change.

Before delving into the question of *whether* changes to the markets are needed, it is appropriate to step back and examine what the markets were intended to accomplish in accounting for public policy and what they were never designed to accomplish in terms of driving public policy.

One can think of the centrally organized markets like a kitchen blender: You add ingredients, push the "mix" button and the blender produces the desired mix of resources given those ingredients. In the same way, market participants and public policymakers provide the necessary inputs to the market — in the form of cost-based and price-based bids from resources, environmental constraints on particular units, or renewable portfolio standards (RPSs) driving the demand for particular types of generation. The market, like the kitchen blender, mixes all those ingredients and produces the most cost-effective and efficient mix of resources based on those ingredients. And just as it would be inappropriate to blame the kitchen blender when the recipe does not come out to our liking, so too should we not blame the markets if we did not first include, as an ingredient, the policy direction and potential outcomes we wanted to achieve.

In short, the centrally organized markets should be viewed as a tool that responds to policymakers' decisions, not an independent driver of policy.

In short, the centrally organized markets should be viewed as a tool that responds to policymakers' decisions, not an independent driver of policy. Accordingly, as we examine the

[7] PJM operates the world's largest wholesale competitive market for electricity. PJM operates in 13 states plus the District of Columbia and serves a population of over 61 million. Craig Glazer serves as PJM's Vice President of Federal Government Policy and is based in Washington, D.C.

future of markets, the right question to ask is whether and how can they continue to serve as an effective tool that blends the ingredients into the most efficient and cost-effective solution for consumers.

This backdrop is important to keep in mind as we examine specific questions about the centrally organized markets in light of the changes occurring around us.

1. Are today's centrally-organized market designs adequate to accommodate state public policy goals, and what potential design changes would further enable deployment of resources that achieve the goals of reliability, affordability and resource mix?

State public policy goals as well as reliability goals serve as ingredients to the market blender in a variety of ways. "Accommodation" or direct incorporation of these goals into the market design varies based on the particular market in question and the fundamental goal of that particular market.

Incorporation of State Public Policies in RTO/ISO Energy Markets

State RPS requirements are designed to drive renewable energy investment, in order to meet state policy goals, through incenting or mandating purchases of energy from particular types of resources over an annual period. RTO/ISO energy markets are voluntary and provide one means, but not the sole means, to procure energy from specific resources. For example, in PJM for the first nine months of 2016, only 26 percent of all energy transactions were purchases in the spot market, with the balance consisting of purchases through bilateral longer-term arrangements or utility self-supply.[8]

Compliance with state RPS requirements can drive a load-serving entity's purchasing decisions, including its decision as to how much energy to purchase through long-term contracts with specific renewable resources versus through spot market purchases where the particular generation resource mix can vary. To provide increased transparency and verification around both long-term and spot market purchases of renewable energy contemporaneous with implementation of RPS requirements, PJM and other RTOs/ISOs, in response to state requests, augmented their energy markets by developing tradable certificates which attest to the injection of specific quantities of renewable energy into the grid. These certificates serve as a verification tool for load-serving entities seeking to demonstrate compliance with state RPS requirements.

In essence, the energy market (as well as tradable certificate programs) provides a trading platform and price discovery tool for both renewable resource sellers and load-serving entity buyers. In turn, energy prices are influenced by the various state RPS requirements

[8] Quarterly State of the Market Report for the PJM Market. Quarterly and Annual State of the Market Reports are prepared by PJM's independent Market Monitor. The most recent quarterly State of the Market Report can be accessed at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016q3-som-pjm.pdf.

and the degree of bilateral versus spot market purchases of renewable resources being undertaken in support of those standards.[9] As a result, the energy market provides transparency, flexibility and a price signal that supports efficient contracting for long-term sources of renewable energy and thus supports, but does not control, purchasing practices by an individual load-serving entity to meet a state RPS requirement.

Accommodation of State Policies in Capacity Markets

Unlike energy markets which are voluntary in nature, capacity markets are designed to ensure the availability of adequate resources to meet the future reliability needs of the overall RTO/ISO footprint. To avoid economic or physical withholding, all available generation resources in the region are required to offer into the capacity market. The market then clears those supplies against an administratively set demand curve. Moreover, both demand response and energy efficiency resources are also eligible to bid into the capacity market and serve as resources that can displace generation in the supply mix. The capacity clearing price, which is derived from the intersection of the supply curve (set by the aggregate of all of the bids) and the demand curve (set administratively based on the cost of new entry of the most efficient resource available under today's technology to meet the next increment of demand). It is designed to serve as an investment signal, the level of which is influenced by whether the RTO/ISO is in an overall supply surplus or supply deficit situation three years forward.[10]

[G]iven the focus of capacity markets to ensure reliability at an efficient price, issues such as state preferences for particular attributes are simply not design features of today's capacity markets.

The capacity markets (like the energy markets) have largely met their stated goal of incenting needed new investment and ensuring that the reliability needs of the region are continuously met.[11] But just as with the blender analogy above, the capacity markets were not designed to choose among different types of resources based on their environmental characteristics or state policy preferences for clean resources that equally meet reliability needs based on their carbon intensity or other environmental attribute. Rather, given the focus of capacity markets to ensure reliability at an efficient price, issues such as state preferences for particular attributes are simply not design features of today's capacity markets.

[9] By driving more renewable purchases, state RPS requirements, by definition, impact the overall mix of generation available in the spot market as well as generation available for procurement under long-term contracts. Prices are affected as a result, with lower energy prices stemming from the zero fuel costs incurred by renewable resources.
[10] Although participation in the capacity market is largely mandatory, specific rules have been developed to allow entities such as regulated utilities and public power to "self-supply" their resources and ensure that those resources clear in the market. This feature in turn assures that those resources are available to the RTO/ISO to meet its overall reliability needs.
[11] See 2015 State of the PJM Market Report: www.monitoringanalytics.com.

There are a number of reasons for this. For one, given that the RTO/ISO is procuring for the region as a whole, if the RTO/ISO were to add one state's preferred resource mix into the capacity market, all other states would end up paying for that policy choice through the single RTO/ISO-wide pricing feature of the capacity market. Second, the capacity market design recognizes that in a system emergency, all resources are needed to address the needs of the grid as a whole. Given the interconnected nature of the grid, a single state cannot have an exclusive "call" on resources that are needed to ensure reliability for the system as a whole. In essence, the capacity market's function is rooted in reliability of the region as a whole by design. Absent regionwide agreement on changes to a resource mix, the capacity market cannot prefer a particular state's preference for certain types of resources given the reliability needs of the region as a whole.

Discussion has ensued in certain RTOs/ISOs, most notably PJM and ISO New England, as to whether the existing capacity market designs should be modified so as to allow states, as a matter of pricing, to provide part of their capacity needs through state-selected resources rather than through the blended mix that is developed through the clearing of a single price for capacity in the capacity market as a whole.[12] Although load-serving entities such as public power can "self-supply" and even subsidize their own resources today with guaranteed clearing in the capacity market (as noted in the footnote above), the discussions in PJM and ISO New England focus on accommodating broader state government policy choices that would apply across-the-board to all load-serving entities, including those that do not own generation. While addressing state activity in this area continues to be important for consideration, given various state subsidy programs supporting in-state coal and nuclear resources, any market design changes to accommodate these state actions also needs to ensure that the overall investment signal that is so important to maintaining reliability across the entire region is not eroded. Nevertheless, as we see increased calls from policymakers for devolution of authority from the federal government to the states, RTOs/ISOs such as PJM recognize the need to engage stakeholders in debate on how such state preferences can be accommodated without having individual state preferences affect prices in neighboring states that have not embraced that particular policy choice.

[12] In PJM's market design, for example, an entire RTO zone which can meet all of its projected reliability needs through resources in that zone can "opt out" of the capacity market. The question being debated is whether a state can choose to remove or subsidize individual resources (be they generation or demand response) even if they do not have all of their resources available in their state to meet future reliability requirements. See, e.g., http://pjm.com/~/media/committees-groups/stakeholder-meetings/grid-2020-focus-on-public-policy-market-efficiency/meeting-materials/20160816-potential-alt-solution-to-the-min-offer-price-rule-for-existing-resources.ashx.

Longer-Term Procurement of Capacity Resources

> ***[L]onger term procurement raises questions as to risk tolerance and risk allocation.***

Other issues, such as whether capacity markets should procure resources for a longer period than today's annual procurement three years forward, raise their own set of questions for policymakers and stakeholders. For one, RTO-/ISO-wide multi-year procurement would provide more certainty for longer-term investment than exists today but could quickly run afoul of states wishing to add (or change) their own policy preferences over time. We have certainly seen state policy choices change as a result of elections and other events.[13] Longer-term procurement by the RTO/ISO may make those policy changes harder to effectuate. Moreover, longer-term procurement raises questions as to risk tolerance and risk allocation. We have seen many examples of decisions based on one set of natural gas price or policy assumptions become obsolete over time. Care would be needed in any longer-term capacity market procurement to ensure that the risk, over time, of the original assumptions not bearing out is appropriately allocated between investors and customers.

2. What are the market impacts of environmental regulations further constraining the deployment of fossil fuel resources?

Today's environmental regulations chiefly take aim at large sources of emissions — which by definition are large central-station power generators, most notably coal-burning power plants. Nevertheless, we are increasingly seeing environmental restrictions on deployment of natural gas units — restrictions in the form of emission limitations during the summer ozone season as well as environmental challenges to the siting of new natural gas pipelines.

From an operations viewpoint, restrictions on coal plants put a major crimp in one of the traditional hallmarks of reliability — an on-site coal pile available to keep the plant operating anywhere from 25 to 55 days. As we become dependent on fuel transportation in the form of pipeline deliveries (or truck deliveries for backup oil supplies), the operation and services offered by pipelines will need to become more integrated with electric operations. Important gas/electric coordination work in this area has begun, but paradigm shifts will be needed in the pricing and regulation of pipeline services to better align this critical supply chain to the changing needs of the electric industry.

From a pricing perspective, the increased dependence on natural gas introduces a greater degree of price volatility than we have seen in the past. For example, in the PJM region 2016 prices have been 25 percent lower than in the corresponding period in 2015. Natural gas

[13] For example, the state of New Jersey was one of the founding members of the Regional Greenhouse Gas Initiative (RGGI), but withdrew from RGGI after an administration change in the state.

prices in recent months have reached record low levels and may stay at those levels for some time. But natural gas for electric generation has many competitors ranging from fuel-on-fuel competition from oil to competition for supply from heating load, industrial processes and, increasingly, foreign exports. All of these factors will affect the volatility of natural gas in a way we never had to deal with when examining fuel prices largely serving one need, as is the case with coal and uranium.

Moreover, just as electric utility ownership of coal mines led to some notably poor outcomes for consumers,[14] so too should we be cognizant of the increased role of natural gas producers serving as "anchor shippers"[15] sponsoring new pipelines. Whether over time there may be undue vertical market concentration in the ownership of critical infrastructure such as pipelines is an issue which will need to be examined in the future. Unfortunately, as with many regulatory regimes, examination of this issue today is divided between many different agencies of the federal government, no one of which is able to examine the larger market trends associated with potential concentration of ownership of needed infrastructure. These will increasingly be future challenges for the industry.[16]

3. What are the market impacts of integrating increasingly higher levels of renewable resources with zero marginal cost?

Today's growth in renewable resources brings with it both operational and price impacts. From an operations perspective, given the variable output of renewable resources, grid operators need to increasingly become dependent on fast-starting flexible resources such as natural gas combined-cycle units to back them up. Over time, this increased dependence on natural gas units will trigger increasing swings in demand on the natural gas pipeline system and require pipeline operators to utilize increasingly sophisticated tools to optimize deliveries of natural gas, such as management of "line pack" in order to maintain adequate pipeline pressures.[17] These challenges are not insurmountable but will require a far more

[14] For example, contentious issues concerning above market pricing for coal from mines owned by the American Electric Power Company led to litigation and jurisdictional battles between the states, the Federal Energy Regulatory Commission (FERC) and the Securities and Exchange Commission. See, e.g., *Ohio Power Company vs. FERC,* 880 F 2d 1400 (1989). At the time the Securities and Exchange Commission had authority over the pricing of coal from such affiliate mines as a result of its authority under the now-repealed Public Utilities Holding Company Act. 15 USC Section 59m(b).

[15] In carrying out its statutory responsibility to site new natural gas pipelines, the Federal Energy Regulatory Commission does not make its own independent determination of need. Rather, it presumes need if there are long-term contracts from shippers (known as anchor shippers) willing to commit to a long-term off-take of supply from that proposed pipeline to support the capital costs associated with its construction.

[16] See Pechman, Carl. *Modernizing the Electric Distribution Utility to Support the Clean Energy Economy.* U.S. Department of Energy. Aug. 25, 2016. https://www.energy.gov/epsa/downloads/modernizing-electric-distribution-utility-support-clean-energy-economy.

[17] Line pack represents the actual amount of gas in the pipeline, including gas reserved in the pipeline to ensure maintenance of adequate pipeline pressure.

flexible and responsive electric and natural gas pipeline infrastructure than necessarily exists today.

Energy storage may be a promising bridge technology to manage the variable nature of renewable resources' output, but given the limited duration of today's grid-connected batteries and the need to set aside time to both charge and discharge, energy storage cannot be viewed as a singular answer to these challenges.

From the perspective of centrally organized wholesale electricity markets, the zero fuel costs of renewable resources will drive energy prices lower. This can significantly dampen the investment signal for new natural gas resources and pipeline infrastructure needed to provide backup for those renewable resources, and negatively impact other capital-intensive zero carbon emitting resources such as nuclear. As a result, in those regions with centrally-organized capacity markets or utilizing traditional regulatory models overseen by state regulators, there will be an increased dependence on those vehicles to provide the necessary financial support for a wide array of resources to meet system reliability needs in a time of falling energy prices.[18]

[D]ependence on administrative tools such as capacity markets in the centrally organized markets, state subsidies for particular types of units or rate base regulation could well become more rather than less prominent over time to provide the necessary revenues to cover the fixed costs of a fleet more dependent on renewable resources with backup fossil or nuclear generation.

The recovery of fixed costs of resources through either capacity markets or rate base regulation remains contentious.[19] But contention does not erase the fact that the industry remains highly capital-intensive, resulting in dependence on administrative tools such as capacity markets in the centrally organized markets. State subsidies for particular types of units or rate base regulation could well become more rather than less prominent over time to provide the necessary revenues to cover the fixed costs of a fleet more dependent on renewable resources with backup fossil or nuclear generation.[20]

[18] Demand response could theoretically provide another vehicle to support the variable nature of renewable resources, but the public's tolerance for frequent curtailment in response to cloud cover or wind variability remains untested.

[19] For example, the increased costs of the Vogtle nuclear plant and Kemper coal-gasification plants have caused increased focus on some of the anomalies of rate base regulation results when compared with competitive market outcomes.

[20] Extensive analyses have illustrated the benefits to consumers of investors bearing the risks associated with investment under a market model as opposed to a more traditional cost of service model. For example, see http://www.pjm.com/~/media/768E4AC9442A428AA83776AFDBF48929.ashx.

4. **Are today's market designs adequate to acquire the flexible resources needed to better integrate increasing levels of variable energy resources at least cost?**

RTOs/ISOs, with the support of FERC, have been able to retool their markets to incent development and appropriately compensate more flexible resources such as demand response, energy storage and fast-ramping generating resources. In the PJM market, changes to compensation for frequency regulation have attracted fast-responding resources such as batteries and other forms of energy storage. By the same token, both demand response and energy efficiency are recognized in PJM's capacity markets and are compensated at the full locational marginal price for that location — identical to how generation is compensated.

Nevertheless, there is no "silver bullet" for ensuring enough flexible resources to compensate for the variability of renewable resources. Although energy storage in the form of batteries is a promising new technology, to date, batteries can operate for only a limited duration, which makes it difficult for these technologies to serve as a resource during those periods when peak demand is the highest but renewable resources' output may be limited.[21] Demand response bids often specify significant notification lead times and given a lag in customer response, system operators often have to plan to call demand response in the hours approaching emergency conditions. Although this works well for meeting peak load conditions, the long lead times needed for demand response do not work as well in responding to the variable nature of renewable resources' output, due to sudden changes in wind speed or cloud cover affecting the generation from solar resources. These limitations reflect the physical characteristics of these resources and thus are not easily resolved simply by changing market rules.

Ironically, perhaps the most flexible resource today to cover the variable output of renewable resources remains natural gas combined-cycle and combustion turbine units. And even for these units, limitations abound. Although these gas resources are highly efficient and can ramp quickly to meet demand, the pipeline system that supplies natural gas to these units is not as flexible, oftentimes requiring advance daily nominations with limited flexibility for adjustment along with ratable take requirements imposed during peak periods.[22]

Continuing with the theme of the market as a tool, the market can provide price signals which can incent the development of these more flexible resources. But the market can respond just so far. To the extent renewable resources become the dominant generation

[21] For example, wind output is usually the highest at night, while the system's peak demand is usually in the afternoon in the summertime. This duration limitation is one of the principle reasons that batteries have gravitated toward participation in the PJM regulation market rather than the energy or capacity market.
[22] "Ratable takes" are requirements in pipeline tariffs that the user take the same level of gas throughout the operating day so as to allow the pipeline to maintain adequate pressure during peak conditions.

resource, operational challenges will occur — challenges which can only be met by the installation of more supporting infrastructure in the form of a full array of energy storage resources, natural gas units, more flexible demand response resources, and increased pipeline and transmission infrastructure.[23]

As state policymakers debate changes to RPS requirements, it is imperative that more analysis be undertaken before unrealistic or costly goals are set without regard to their impact on system reliability or customer cost. To date, system operators have largely been absent from these legislative debates. As we move forward, this paradigm will need to change as legislators and, in the case of ballot initiatives, voters, will need to recognize the trade-offs associated with their policy choices related to various renewable portfolio proposals.

[T]here are many policy and economic trade-offs for project developers, electricity customers and policymakers which need to be weighed. But … the solution is not necessarily to condemn the workings of the market "blender" itself, but instead to come together to agree on which ingredients we wish to add on the front end in our quest to ensure, on the back end, cost-effective, efficient and reliable solutions for customers.

Conclusion

All of the above questions are ones without simple answers. Like all such complex questions, there are many policy and economic trade-offs for project developers, electricity customers and policymakers which need to be weighed. But, as noted above, the solution is not necessarily to condemn the workings of the market "blender" itself, but instead to come together to agree on which ingredients we wish to add on the front end in our quest to ensure, on the back end, cost-effective, efficient and reliable solutions for customers.

[23] PJM is examining additional operational and planning reforms that will increase the resiliency of the grid going forward. Stakeholder discussion of these issues will follow PJM's release of its paper examining fuel diversity in March 2017.

2. The "Utility Perspective:"[24] Not All Megawatts Are Created Equal

By Jay Morrison and Paul Breakman, National Rural Electric Cooperative Association[25]

Summary

- Wholesale market discussions must begin with retail electric consumers.
- Electric utilities and their regulators must prioritize and achieve a careful balance among numerous goals, including safety, reliability, resource adequacy, affordability, environmental sustainability, economic development, financial stability and more. Those priorities vary according to local consumer preferences.
- Utilities' numerous obligations can most efficiently be pursued if the utilities have the flexibility to optimize their investments across a portfolio of generation, transmission, distribution and distributed energy resources (DERs) in order to maximize value to consumers.
- Changes in the industry's generation mix and changes in regulatory obligations complicate the effort to optimize investments and increase utilities' need for flexibility and optionality.
- Competitive bilateral and centrally-organized wholesale markets in much of the country have largely enabled utilities to acquire the resources they need to meet their obligations, including those driven by state policy goals. But some changes in the Eastern RTOs/ISOs in the past six years have been counterproductive, reducing utilities' options and flexibility, and undermining their ability to cost-effectively meet all of their obligations to their retail electric consumers and regulators. Those changes, and the philosophy underlying them, should be reconsidered.
- Increased variable generation may require new ancillary services, other energy market reforms, or both to enable system operators to acquire essential reliability services such as fast ramping and inertia, and to compensate generators that provide those services.
- Increased variable generation also increases the importance of long-term bilateral contracts and retail consumer relationships.

[24] The electric utility industry speaks with a unanimous voice on very few questions, including organized markets. The electric utility industry includes both traditional utilities with an obligation to serve the long-term needs of consumers and those utilities in restructured states whose delivery and generation resources were separated into different companies facing different regulatory and market conditions. The industry also includes investor owned, publicly owned, federally owned, and consumer owned electric utilities, each of which comes with very different incentive structures. Moreover, even within any one utility sector, different investment strategies, regional pressures, consumer preferences, and legal obligations would lead different utilities to take a different view of the adequacy of organized wholesale market design. To simplify the drafting process, this report reflects primarily the perspective of electric cooperatives which are, with very few exceptions, traditional utilities that continue to have an obligation to serve the long-term needs of consumers. This report tries to point out when that viewpoint is significantly different from others in the utility sector.

[25] NRECA is the national service organization for more than 900 not-for-profit rural electric utilities. Electric cooperatives bring power to 75 percent of the nation's landscape and 12 percent of the nation's electric customers, while accounting for approximately 11 percent of all electric energy sold in the United States. NRECA's members participate in all of the organized wholesale electricity markets, as well as single Balancing Authority Areas throughout the country. Jay Morrison serves as NRECA's Vice President of Regulatory Affairs. Paul Breakman serves as NRECA's FERC Counsel and is a Senior Director of Regulatory Affairs.

Serving Consumers: It's What We Do — The Utility Perspective

Begin With Retail Electric Consumers

Discussions of the electric utility industry and wholesale electric markets must begin with retail electric consumers. Electric utilities exist to provide these consumers with an essential service. And, boiled down to its essence, wholesale electric markets (bilateral and organized) exist to enable electric utilities to acquire the resources they need to meet that obligation more efficiently than they could if they relied entirely on their own investments. The wholesale markets should provide wholesale customers non-discriminatory access to the resources they need to serve their retail consumers, at just and reasonable prices.

That then raises the question of what it is that retail electric consumers want. The answer to that question is complicated. Certainly, consumers want heating and cooling, light, refrigeration and energy to power their electronic devices, homes, businesses and communities.

Safety is a given. Consumers would not tolerate a system that creates undue hazards for people or property.

[B]oiled down to its essence, wholesale electric markets (bilateral and organized) exist to enable electric utilities to acquire the resources they need to meet that obligation more efficiently than they could if they relied entirely on their own investments.

Utilities also know from consumer surveys and from the complaints consumers file with the utilities and their regulators that consumers want power quality. Lights should not dim, televisions should not blink, and manufacturing processes should not be interrupted by surges or sags in voltage.

Consumers want reliability. Light should be available at the flip of a switch, and the ice cream should not melt. Businesses and manufacturing processes must continue without interruption due to local system failures, cascading outages on the bulk electric grid, or insufficient capacity available to serve load.

We know consumers are sensitive to price, not only wanting prices to be low, but to be fairly stable over time. Residential consumers and businesses alike have to be able to budget and significant price swings make that difficult. Whether it is budget billing, pre-paid service, interruptible rates, energy efficiency investments, smart meters, rooftop solar, or any of a multitude of other options, some consumers also want the ability to help reduce or control their power costs. This seems to be true both in regulated and in restructured states. Certainly, state regulators in the largely restructured Northeast expressed great angst at the price spikes that occurred during the polar vortex of 2014.

Consumers have also told their utilities and their elected officials at the state and federal levels that they want the power they receive to be clean. Increasing numbers of consumers are directly supporting renewable resources by investing in rooftop solar, community solar or green credits. Many consumers also express their demand-side preferences by voting for state policymakers that will support renewable energy and environmental regulations. This is as true in restructured states as it is in traditionally regulated states. The Northeast states, most of which are restructured, have largely all adopted renewable portfolio standards. They also led the country on climate policy by establishing the Regional Greenhouse Gas Initiative.

In some parts of the country, consumers and their elected officials have also partnered with local utilities to strengthen their communities. Many utilities not only pay taxes to support schools, roads and community services, but also engage in economic development activities to attract new employers to their territories and deliberately locate offices, new generation resources, and other infrastructure investments within their communities to help keep their consumers' money in the local economy.

Finally, it is important to consumers that their utilities be financially stable, even though they may not voice that opinion. This is obvious for electric cooperatives, which are owned by the consumers they serve. It is also true for "public power" utilities[26] and investor-owned utilities. Strong balance sheets are essential so that utilities can make the investments needed to effectively serve their consumers. Poor financials drain funding away from the maintenance required to ensure power quality and reliability, and increase the cost of financing required for investments in new infrastructure. That is why traditionally regulated states provide regulated utilities the opportunity to recover prudently incurred costs. Some of those states have gone further and offered utilities advance assurances that they will be able to recover more risky investments in nuclear or clean-coal generation that the states believe is needed to serve consumer interests. It is also why regulators in some restructured states are looking for means by which to provide financial support to the owners of valuable assets, even if they are not in a utility's rate base.

Goals Must Be Prioritized and Balanced Against Each Other

Of course, not all consumers, communities, states or regions prioritize among the various goals for the electric system in the same way. The differences in the details of different renewable portfolio standards (RPS), for example, demonstrate that some consumers, in their role as voters, prioritize renewable energy, local energy resource development, and support for new technologies more or less highly than others. Some states mandate minimum levels of investment in renewable energy, but leave it to the regulated utilities to find the lowest cost means of reaching those targets. Meanwhile, others express preferences or provide set-asides

[26] As distinguished from electric cooperatives which are private, nonprofit corporations are owned by their consumer-members, most public power utilities are owned by municipalities, with others are owned by counties, public utility districts and states.

for locally sourced resources or specified technologies. Some states have expressly balanced their interest in renewable resources with their desire for low-cost power by building price caps into their RPS. Others have declined altogether to impose renewable energy requirements.[27]

Prioritization is important because the goals of safety, power quality, reliability, affordability, environmental sustainability, community development, financial stability and others can conflict with one another.

No utility can say that it will seek to "max out" on all of the goals it is asked to achieve. The more it pursues one goal, the more it may undermine its efforts to accomplish another. Increasing expenditures to make the system safer, to reduce distribution-related outages, to increase generation reserves, or to exceed minimum North American Electric Reliability Corporation (NERC) compliance requirements may increase rates. Investment decisions that are aimed at minimizing energy costs by reducing hedging expenses today may make power prices more volatile in the future. Efforts to keep rates affordable by postponing rate increases when costs go up may undermine the long-term financial stability of the utility and thus its ability to make the investments needed to preserve safety and reliability.

To complicate matters, the relationship between these goals is neither linear nor certain. Investments in emissions controls or renewable resources may increase costs in the near term, but at some level they may reduce environmental compliance costs, fuel costs or cost volatility in the future. Investment in economic development may increase rates in the short term, but may strengthen both the utility and its consumers financially in the longer term, making power more affordable in the future.

Faced with these multiple, intersecting, and often conflicting obligations, utilities must develop an investment strategy that reaches the best possible balance among them. That requires a series of policy decisions by each utility, its board of directors, and its regulators, whether that is a state public utility commission, public power governing bodies and their consumers, or a cooperative's consumers. The utility and its regulators must decide what trade-offs to make amongst the various goals the utility must pursue and the level of risk they are willing to take that their choices will prove out in the future.

Critically, every utility and every regulator will make a different set of decisions based on their evaluation of their consumers'/constituents' priorities among the goals, their risk tolerance, their evaluation of industry conditions in the area where they operate, and their evaluation of the direction the industry is trending. That is the nature both of the political process and of any business.

[27] See Renewable Portfolio Standard Policies. February 2017. http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2017/02/Renewable-Portfolio-Standards_Feb2017.pdf.

Utilities Need Flexibility to Customize Resource Portfolios

Utilities tend to meet their obligations, in light of these interrelated policy decisions, by investing in a portfolio of resources that may include generation, transmission, distribution, and DERs. They design that portfolio, add to it, and subtract from it in an effort to optimize it to accomplish the goals they are directed to meet in the most cost-efficient fashion they can in light of the costs, risks, and operational traits of different resources, the interactions amongst those resources, their regulatory and market environments, and the changes they anticipate to those conditions.

By acquiring generation from resources with different fuel sources, utilities can manage fuel price and availability risks. By entering into contracts with known and trusted business partners, utilities can hedge against counterparty risks. By investing in transmission or local generation, utilities can reduce delivery or congestion risks. By investing in flexible DERs, utilities can reduce their exposure to wholesale market costs and satisfy consumers who are interested in managing their power supply costs.

For example, by owning some generation (where allowed), entering into contracts of different durations for some of their needs, and buying some generation out of short-term organized markets, utilities can hedge against the regulatory risks on one hand that might make their owned assets uneconomic in the future, while hedging against the risk on the other hand that short-term market prices may spike. By acquiring generation from resources with different fuel sources, utilities can manage fuel price and availability risks. By entering into contracts with known and trusted business partners, utilities can hedge against counterparty risks. By investing in transmission or local generation, utilities can reduce delivery or congestion risks. By investing in flexible DERs, utilities can reduce their exposure to wholesale market costs and satisfy consumers who are interested in managing their power supply costs.

The resources in which a utility invests must be considered in light of its existing portfolio and business needs and the interaction between different elements of the integrated portfolio. Take investments in natural gas and wind, for example. An investment in wind generation can decrease the value of an existing investment in a natural gas generating plant by reducing the hours in which it dispatches. On the other hand, when the wind displaces the gas generation, it can also reduce the utility's fuel costs and its exposure to fuel price risks. Increases in wind generation can also increase the value of a gas generator if that generator has sufficient flexibility to meet system ramping needs as the wind rises and falls. Investment in new transmission might increase reliability and enhance access to distant generation options, but an investment in a combination of local peaking generation and DERs might provide the same reliability value at lower cost (if the requisite gas pipeline and land are available for the gas turbine), provide local jobs, and provide a hedge against peak market prices. The choice between the two investments will depend on the utility's evaluation of their total cost and value in light of local needs, market conditions and consumer and regulatory preferences.

It is important to recognize that even between seemingly equivalent resources, there may be significant differences. For example, two gas plants may:

(a) draw from different gas pipelines that are more or less reliable, flexible and affordable;

(b) export power across different transmission resources that may be more or less likely to face congestion or reliability risks;

(c) have newer or better generation or emissions control equipment with different ramping capabilities, different minimum loads, and different environmental characteristics;

(d) benefit from more or less experienced operators; and

(e) be willing to enter into different contracts with different terms, different lengths and different rates.

The process of resource portfolio design is more challenging because each utility must make its investment decisions in the context of a broader interconnected and integrated industry. A utility serving in a region with significant wind generation may find that its best choice for a new resource is a peaking plant that integrates smoothly with the existing wind resources, whereas a utility in a region with very few variable generation options but an oversupply of gas generation might find that a new nuclear plant best permits the utility to meet future energy needs while mitigating against fuel price volatility. Moreover, each utility must pay attention not only to what other players in their region *have* done, but what they *might* do. Decisions other industry players make to build or decommission a power plant, to build or decommission a transmission line or gas pipeline, or to open or close a new factory or mine with a significant load can make a utility's past investment strategy appear inspired or foolish.

Regulatory Risk Increases Utilities' Need for Flexibility and Optionality

Utilities' need to manage risk through careful portfolio management is further heightened by the risks they face in the regulatory arena. During the early 1970s, the industry watched gas generation start to displace coal, only to get cut off at the knees by regulatory-induced gas shortages and the Fuel Use Act.[28] Gas then resurged when the Fuel Use Act was repealed, gas deregulation encouraged new gas supplies to be brought to market, and new environmental regulation began to disfavor the coal generation utilities once built at the government's urging. Over the past few years, the Mercury and Air Toxics rule, the Regional Haze rule, the Cross-State Air Pollution rule, the Effluent Limitation Guidelines, and others have significantly increased the cost of operating coal generation. The Clean Power Plan also promised to force some coal

[28] In the Power Plant and Industrial Fuel Use Act of 1978, Public Law 95-620, Congress effectively prohibited the use of natural gas for generation because of apparent gas shortages. In its place, the Carter Administration aggressively advocated the use of coal for generation. The Fuel Use Act was repealed in 1987.

generators to reduce output or shut down, though the Clean Power Plan's future is now uncertain.[29]

Of course, these rules only added to the economic pressures that historically low gas prices have already put on coal generation. Those pressures, however, are also dependent on regulatory choices. If future fracking regulation, for example, imposes significant costs on gas, coal and gas may once again switch places in the dispatch queue.

Wind generation has grown in fits and starts as the Production Tax Credit has been authorized, lapsed and reauthorized.

Small-scale solar generation penetration levels in the states can be easily predicted by looking at the rules individual states have adopted for retail rates, net metering and renewable portfolio standards. Dramatic swings in regulatory policy, as we have seen in Nevada over the past few years, have led to the rapid growth, retreat, and now the likely resurrection of the residential solar industry in the state.

Given this history, each utility knows that it must not only develop a portfolio that complies with existing regulatory requirements, but one that is sufficiently diverse and flexible to be able to adjust to meet the needs of future regulatory requirements.

First, the organized markets should be designed to enable utilities to create, maintain, and adjust their portfolios as needed to meet changing regulatory requirements. Second, given the increasing number of environmental regulations that are making it more expensive to preserve existing fossil fuel resources, the RTOs/ISOs can no longer take their existing capacity surpluses for granted. [...] Both of those lessons should lead to organized market rules that facilitate and enable the long-term contracts and state incentives required to promote investment in new resources utilities need as they readjust their resource mix....

This history also offers two lessons for the organized markets. First, the organized markets should be designed to enable utilities to create, maintain and adjust their portfolios as needed to meet changing regulatory requirements. Second, given the increasing number of environmental regulations that are making it more expensive to preserve existing fossil fuel resources, the RTOs/ISOs can no longer take their existing capacity surpluses for granted. Investments in new resources will be needed to comply simultaneously with environmental regulations and resource adequacy requirements. Both of those lessons should lead to organized market rules that facilitate and enable the long-term contracts and state incentives required to promote investment in new resources utilities need as they readjust their resource mix, even if those new resources cost more on a levelized fixed-cost basis than existing resources. As discussed in more detail below, organized markets should not treat those

[29] See, generally, Clean Power plan. https://www.epa.gov/cleanpowerplan and Clean Power Plan Petitions for Reconsideration January 2017. https://www.epa.gov/cleanpowerplan/clean-power-plan-petitions-reconsideration-january-2017.

arrangements as "out-of-market" or increase the cost and risk of making investments in new resources that meet utilities' consumer, business, and policy obligations.

In economic terms, the organized markets should: (1) reduce barriers to entry that raise the cost of capacity and increase reliability risks; (2) reduce barriers to entry for new, innovative and environmentally friendly technologies; and (3) reduce barriers to exit for existing resources that may no longer meet consumer needs as well as new resources might.

It is in this context that we seek to answer the questions presented for this report.

1. Are today's organized market designs adequate to accommodate state public policy goals, and what potential design changes would further enable deployment of resources that achieve the goals of reliability, affordability and resource mix?

Some Changes to the Market Rules for Eastern RTOs/ISOs Are Needed to Accommodate Retail and Wholesale Consumers' Preferences.

To answer this question, we should start by properly reframing it. State policies are not adopted in a vacuum. States adopt policy in response to voter preferences. As discussed above, in the context of the electric utility industry, those policies reflect the buyer-side preferences of retail electric consumers *qua* voters. Thus, we should be asking not whether organized market designs are adequate to accommodate state public policy goals but whether they are adequate to meet consumer preferences as those are expressed through the political process.

As utilities, it is also important to look at this question from the perspective of the wholesale customer. As heavily regulated businesses, utilities must put together and maintain resource portfolios that meet all of their regulators' expectations, including safety, reliability, low price, price stability and environmental compliance. The portfolio must also permit utilities to manage a wide range of business risks, including regulatory change. From that perspective, the question should be reframed to ask whether organized markets are adequate to accommodate the needs of wholesale customers, including their obligation to comply with state and federal regulations.[30]

For us to answer these reframed questions, it would be helpful first to clarify the difference between operational time frames and planning time frames.

[30] These reframed questions should help us move away from the assumption that some seem to make that: (1) state policies are somehow external to the proper functioning of markets, (2) they therefore inherently interfere with efficient market outcomes, and (3) those policies should therefore be marginalized to the greatest extent possible in the design of markets. If we recognize instead that state policy reflects buyer-side preferences, then those policies can be seen less as interference with the market and more as a tool for incorporating demand-side preferences into markets. It is true that some state policy tools are far more economically efficient than others but there is no room in this report for that discussion.

The first responsibility of each RTO/ISO is to operate the grid in its region reliably and efficiently. To do that, the RTO's/ISO's organized markets commit resources on a day-ahead basis and then conduct security-constrained economic dispatch of the generation resources over which they have control in real time. That function ensures that the most cost-effective resources are being operated consistent with reliability at all times. It ensures non-discriminatory transmission access at a non-pancaked rate across the entire RTO/ISO region.[31] By performing that function, the organized markets tend to reduce the cost of energy for consumers. They also can improve reliability, as that term is used in operational time frames: "operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."[32]

Different utilities have a variety of recommendations for improving energy markets and RTO/ISO governance practices, but some of those are beyond the scope of this report. In general, it is probably fair to say that most utilities that have joined RTOs/ISOs (enthusiastically or not) find that the organized *energy* markets have, in general, made it easier for them to meet the needs of their consumers and regulators.

Planning time frames, transmission planning and resource planning are a whole different animal.

As much as 10 or even 15 years before a consumer flips the switch with the expectation that the lights will turn on, utilities have begun planning for, designing, permitting, building and bringing into operation the new infrastructure needed to meet that expectation. Some resources, such as a new gas peaking plant, may be able to proceed from "go" decision to operation in less than three years. Others, such as a nuclear plant or a transmission line that has to cross sensitive lands, might take decades. Even DER investments, such as energy efficiency and demand response programs, can require years to develop, advertise, and ramp up to significant levels. If a utility is to maintain a balanced and diversified portfolio of resources that is capable of meeting the range of goals it is asked to achieve, it must think ahead. In that process, the organized markets' role is not nearly so clear.

One element of centrally organized markets' — or perhaps more appropriately the RTOs'/ISOs' — role in the planning time frame is the RTOs'/ISOs' responsibility to manage the transmission planning process to ensure that the transmission grid is adequate to

[31] Prior to the formation of ISOs and RTOs, a utility seeking to obtain delivery from a distant resource could be required to pay a separate transmission rate to each of the intervening transmission owners. Those "pancaked rates" could significantly increase the cost of the resource, undermining competition. Many transmission-dependent utilities strongly supported the formation of ISOs in order to gain access to a wider range of competing generation providers at a single regional transmission rate. That access expanded wholesale competition and drove down the cost not only of transmission service but also wholesale power.

[32] Federal Power Act Section 215(a)(4).

maintain reliability, to provide efficient access to low-cost generation resources, and to mitigate the market power of large market players, all without unduly raising the cost of transmission service. It is important that FERC and the RTOs/ISOs evaluate the effectiveness of the Order 1000 transmission planning process[33] and FERC's transmission rate policies as they are critical elements in every utility's efforts to meet the needs of its consumers. It is well worth asking whether the transmission planning process adequately allows utilities to meet state policies.

It is equally important to ask the question posed by the Energy Policy Act of 2005. That is, whether the transmission planning process "meet[s] the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enable load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs."[34] Those questions, however, are beyond the scope of this report.

The other element of organized markets' role in the planning time frame, which is more appropriate for evaluation here, is in facilitating those investments by utilities and others required to meet resource adequacy requirements — that is, to ensure that there is sufficient capacity to meet load plus a reasonable reserve margin.

Traditional wholesale electricity markets exist primarily in the Southeast, Southwest and Northwest. Utilities in those areas look to the bilateral markets and their self-build options, not organized markets, to acquire the generation resources they need.[35]

In the areas of the country served by RTOs and ISOs, utilities have the further option of acquiring shorter-term resources in the organized markets. In the regions served by ERCOT, MISO and SPP, organized markets have been layered over the existing bilateral markets. In addition to the self-build and bilateral market options, utilities can acquire short-term energy resources (and short-term capacity in MISO) in the organized market. Also, because the organized markets' security-constrained economic dispatch ensures non-discriminatory transmission service in real time, utilities can invest in or contract with distant resources with greater confidence. Thus, the organized markets have in some ways increased the

[33] FERC Order No. 1000, 136 FERC ¶ 61,051 (2011), requires all Public Utilities to participate in a regional transmission planning process that satisfies certain open and transparent transmission planning principles in the development of regional transmission plans that *inter alia* identify and propose solutions for transmission needs driven by public policy requirements.

[34] Federal Power Act Section 217(b)(4).

[35] Individual utilities express a variety of concerns with the bilateral markets, including the range of resource options available to them or the costs at which those options are available, the market power of various market participants, the adequacy or cost of transmission to access their resource options, or the risks they face in choosing among those resources. But the bilateral markets are not themselves inherently limiting, and this report is not the right place to dig into individual litigated cases. In short, the more competitive the bilateral markets can be made, the more effectively they can meet utilities' needs.

utilities' options and made it easier for them to meet their consumers' expectations more efficiently.[36]

The prices in the real-time energy markets are also factored into investment decisions. High prices in the short-term markets may encourage some utilities to invest in demand response,[37] new iron in the ground, or longer-term energy contracts as a hedge against those prices, whereas low prices may have the opposite effect.

Prior to 2011, things were much the same in the Eastern RTOs/ISOs — ISO NE, NYISO and PJM — even though all three of the Eastern RTOs/ISOs differ from MISO, SPP, ERCOT and CAISO in that they have mandatory capacity markets[38] (see Figure 2.1.). Until 2011, LSEs were free to build generation, enter into bilateral capacity contracts, or acquire resources pursuant to a state obligation such as an RPS, just as they could elsewhere. That is because they were guaranteed that they could use those resources to meet their resource adequacy obligation — just as they could elsewhere in the country. The LSEs would offer those resources into the market as "price takers," they would buy an equivalent amount of capacity out of the auction in order to demonstrate that they met the resource adequacy obligation, and the revenues from their resources and the costs of the capacity they purchased would offset one another. For the resources to which LSEs already had rights, the mandatory capacity constructs simply served an accounting function. To the extent that LSEs were "short," the mandatory capacity constructs served as "residual markets." Those LSEs that needed additional resources beyond those they had built or contracted for could buy the remainder through the auction, and those utilities and non-utility generators that had excess capacity not already needed to serve load or sold in the bilateral markets competed for that residual demand.

[36] As with the bilateral markets, utilities have expressed a wide range of concerns about different aspects of the organized markets. Many of these concerns are beyond the scope of this report. At heart, FERC should remember as it evaluates the organized markets that the Federal Power Act is a consumer protection statute. The market design must ensure that the system is operated efficiently to ensure that wholesale customers have non-discriminatory access at just and reasonable rates to the resource options they need to meet the long-term needs of their retail consumers.

[37] In Order No. 745, FERC required that the organized markets permit demand response to play a direct role. By leaving it to the appropriate regulatory authority (state public utility commission, public power utility governing body or cooperative board) to decide who could bid certain loads' response into the organized markets, Order 745 also preserved existing utility demand response programs that the utilities had developed as a means of hedging against high energy prices and reducing retail consumers' capacity costs. It is very important to many utilities, including cooperatives and public power utilities, that they be permitted to continue to serve in this intermediate role between their retail consumers and the wholesale electric markets. By taking that role, they are better able to optimize their portfolio for the benefit of all of their retail electric consumers.

[38] While all of the RTOs require load-serving entities (LSEs) to demonstrate that they have rights to sufficient capacity to meet resource adequacy requirements established by the RTO, in the Eastern RTOs' mandatory capacity constructs, that demonstration can only be made by purchasing capacity from the RTOs' centralized capacity auctions.

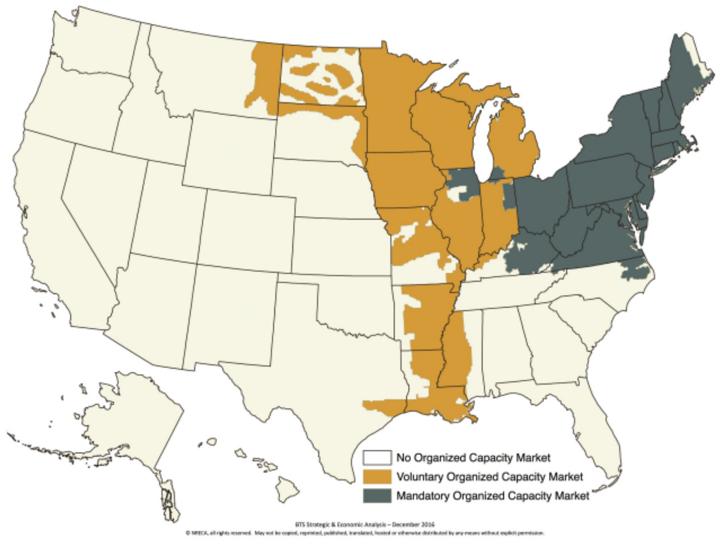

Figure 2.1. Capacity Markets in the United States.

Starting in 2011, pursuant to a series of proceedings at FERC,[39] the market design changed. New resources that LSEs built or contracted for to meet their consumers' capacity needs, including those built pursuant to state requirements, were no longer guaranteed to clear the auction. They would have to compete with all other capacity offered into the auction. The lowest cost resources — as that cost was calculated by the RTO/ISO — would win the auction, regardless of who owned the resources, the type of generation, the fuel used, the generation's operational characteristics, or its environmental attributes. That meant that LSEs might have to pay twice for capacity: once for the resource they acquired because they believed it best met their consumer, business and regulatory needs, and again for generic capacity[40] purchased from the auction to demonstrate compliance with the RTO's/ISO's resource adequacy obligation.

Starting in 2011, [...] the market design changed. New resources that LSEs built or contracted for to meet their consumers' capacity needs, including those built pursuant to state requirements, were no longer guaranteed to clear the auction. They would have to compete with all other capacity offered into the auction. […] That meant that LSEs might have to pay twice for capacity: once for the resource they acquired because they believed it best met their consumer, business and regulatory needs, and again for generic capacity purchased from the auction to demonstrate compliance with the RTO's/ISO's resource adequacy obligation.

[39] For a detailed discussion of the litigation, see Morrison, Jay. "Capacity Markets: A Path Back to Resource Adequacy." 37 *Energy Law Journal* 1, 6 et seq. 2016.

[40] In this way, the organized capacity constructs can be compared to the commodity markets, such as the NYMEX, while the bilateral markets can be compared to the over-the-counter commodity markets. The centrally organized markets manage standardized transactions for fungible products, such as wheat, while the over-the-counter markets

For the first time, this change put the centrally organized markets and the states into direct conflict. For the purposes of the mandatory organized market capacity auction, the RTO/ISO was now deciding which resources were worthy of use, regardless of the policy reasons why the states or the utilities they regulate may have preferred other resources. The states could still require utilities to build renewable generation, support nuclear resources, or encourage new highly efficient gas generation to be built close to load where they believed that to be in the interest of consumers *qua* voters, but if they did, retail electric consumers could end up paying a significant financial penalty.

The changes made starting in 2011 arose from the concept that the organized energy, ancillary services and capacity markets collectively must provide sufficient revenue for non-utility generators to encourage them to maintain or build sufficient resources to ensure resource adequacy. By "self-supplying" — building their own resources or contracting for resources in the bilateral markets — LSEs could increase supply and drive down prices in the organized markets. Similarly, when states direct LSEs to invest in specific resources or provide subsidies to their preferred resources, they too could increase supply and drive down prices in the organized markets. Thus, the RTOs/ISOs concluded that unless self-supply and state-mandated resources are forced to compete on "an even playing field" with the generic, fungible capacity product available through the mandatory centralized capacity market, those resources would undermine the ability of the organized markets to function. The organized markets alone would be unable to provide sufficiently high prices to support independent investment in capacity by those who have chosen to rely solely on those markets for revenue.

Some states and utilities countered the RTOs'/ISOs' argument by saying that the fungible capacity product that could be purchased from the organized market (generic megawatts) is not equivalent to the resources supported by the LSEs and states; that the fungible product is not necessarily backed by iron in the ground that could serve the wide range of purposes the utilities and states were seeking to accomplish.

The RTOs' counterproposal — a regionwide price for each policy preference established if and when all of the states in the region can agree on how to calculate it — is simply inconsistent with the level of local determination and flexibility that utilities elsewhere in the country have and that all utilities need to respond to the demands of their consumers and regulators.

The Eastern RTOs/ISOs have responded that any megawatt of capacity is equivalent to any other megawatt of capacity, that the organized markets' sole responsibilities are to reliability and low prices, and that the markets do not recognize the other policy, business and consumer interests the utilities and states were pursuing. The organized capacity markets do not price environmental attributes, long-term reliability beyond three years, fuel

permit customized transactions for much more specific products in which the price, timing, conditions and risk allocation can all be negotiated to meet the respective needs of the parties.

diversity, or any of the other factors discussed above that are essential to utility investment decisions. If the states want to incorporate other interests into the markets — such as carbon reduction — then all of the stakeholders across the RTO/ISO region will need to reach agreement as to how to price that interest and how to incorporate that price into the RTO/ISO tariff.

The RTOs' counterproposal — a regionwide price for each policy preference established if and when all of the states in the region can agree on how to calculate it — is simply inconsistent with the level of local determination and flexibility that utilities elsewhere in the country have and that all utilities need to respond to the demands of their consumers and regulators. That inconsistency is plain in the restrictions FERC has imposed on New York's efforts to promote renewable resources. That inconsistency is plain in the litigation initiated by non-utility generators against Maryland's and New Jersey's efforts to ensure adequate service for their consumers by encouraging the construction of new gas generation in their states. That inconsistency is plain in the complaints filed against New York's efforts to pursue climate goals by protecting nuclear generation in the northern part of the state. That inconsistency is plain in the complaints filed against Ohio's efforts to preserve existing low-cost resources in the state for the benefit of their retail electric consumers.

Regardless of whether one believes that the states are making wise decisions that are in their consumers' best interests, that question should be decided by voters in those states, not by FERC and the organized markets. It is the voters who are best placed to make policy decisions on their own behalf. The centrally organized markets should not be designed to impose new risks on utilities for making long-term resource decisions based on factors other than price. Nor should they make it more difficult for utilities and state regulators to provide financial support outside of those markets for nuclear resources, renewable resources, highly efficient and ideally located gas generation, DERs, and other resources that provide value to retail electric consumers *qua* voters.[41]

Some have argued that states and utilities do a very poor job of resource planning and portfolio management. Quite legitimately, they point to a number of times where utilities have made investments with the direction or approval of states that proved to be uneconomic when conditions changed. They argue that markets do a much better job of ensuring resource adequacy at low cost to consumers than do utilities and states, especially during times of uncertainty, and insist that retail electric consumers would face less risk and

[41] FERC recognized this in Order No. 745, in which the Commission both required the RTOs to incorporate demand response into the organized markets and left it to the appropriate regulatory authority (state public utility commission, public power utility governing body or cooperative board) to decide whether competitive aggregators would be permitted to bid that demand response into the organized market. The Commission is also proposing to leave it to local regulators to make the same decision with respect to other DERs. Leaving that decision to local regulators is critically important to many traditional utilities that rely upon DERs as an integral part of their resource portfolios.

lower cost if the competitive markets were permitted to do so without state interference — that is, if states would stop picking winners and losers.

Unfortunately, reliance on markets does not eliminate risk to consumers or eliminate the errors that arise when policymakers or utility management picks winners and losers. As Robert Reich explains eloquently in his book "Saving Capitalism For the Many, Not the Few," there is no such thing as a "pure" market. Markets are human creations defined by the rules by which they operate, and those rules pick winners and losers as certainly as state mandates.

An organized capacity construct that operates only three years ahead and that clears based solely on levelized fixed costs will drive the construction of gas generation, because that is the dispatchable generation resource with the lowest levelized fixed costs that can be built in that time frame.[42] By setting the rules as they do, the market operators get the resources that they believe to be the right choice just as surely as states get renewable resources when they establish a renewable portfolio standard. And we are guaranteed to see conflicts in multi-state RTOs/ISOs when the market is designed to value and price only one set of policy goals (adequacy and low levelized fixed costs), while each state in the RTO/ISO region has its own set of policy goals (adequacy, low cost, minimization of price volatility, environmental sustainability, economic development, etc.) and each state prioritizes differently among those goals.

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Ultimately, the conflicts between the organized markets and the states in the Eastern RTOs have created barriers to entry to new resources required to meet state policies and ensure resource adequacy. These conflicts also have created barriers to exit for existing resources that may no longer meet consumer needs as well as new resources might, imposed economic burdens on

[T]he Eastern RTOs should go back six years and restore the mandatory capacity markets to their status as residual markets that supplement, rather than substitute for, the judgments made by utilities, their regulators and their consumers.

[42] See EIA. Levelized cost comparisons help explain value of various electric generation technologies. http://www.eia.gov/todayinenergy/detail.php?id=21492.

existing resources that still do meet consumer needs but are not the lowest cost resources based solely on levelized fixed costs, imposed the risk on LSEs that they might pay twice for capacity — once for the resources they need to meet the needs for consumers and again for generic capacity from the centrally organized markets, and created endless litigation over every detail of the markets' design.

Fortunately, the solution is fairly simple on its face. To eliminate the conflict, the Eastern RTOs should go back six years and restore the mandatory capacity markets to their status as residual markets that supplement, rather than substitute for, the judgments made by utilities, their regulators and their consumers.[43]

2. **What are the market impacts of environmental regulations further constraining the deployment of fossil fuel resources?**

3. **What are the market impacts of integrating increasingly higher levels of renewable resources with zero marginal cost?**

4. **Are today's market designs adequate to acquire the flexible resources needed to integrate increasing levels of variable energy resources at least cost?**

We address all three of these questions together because it is really difficult to parse them out. Neither the reduction in fossil generation nor the increase in variable generation we are seeing in the industry are occurring in isolation. Rather, the changes taking place in the industry's resource portfolio and the impact those changes have on the power markets are deeply interrelated.

Increased variable generation may require new ancillary services, other energy market reforms, or both to enable system operators to acquire essential reliability services such as fast ramping and inertia and to compensate generators that provide those services.

In many parts of the country, variable generation is increasingly displacing fossil generation. A combination of quickly falling prices for wind turbines and solar panels, federal and state tax incentives, and state mandates have led to a significant expansion of wind and solar capacity. At the same time, increased environmental regulation has increased the costs and risks faced by fossil generators, leading to early retirements of many coal plants and some gas plants. Those environmental regulations also have made it highly unlikely that new coal capacity will be built for the foreseeable future.

Variable generation is also displacing fossil generation in the dispatch stack. At utility scale, wind and solar resources tend to be dispatched first by system operators because they have

[43] The authors recognize that is not quite as simple as it sounds. The Eastern RTOs must still deal with the fact that competitive LSEs in the region have limited incentives today to make the investments required to ensure resource adequacy. That problem, however, can be solved. For some ideas as to how, see Morrison, supra, and Hamal, C.. "Solving the Electricity Capacity Market Puzzle: The BiCap Approach." *Navigant Econ.* July 2013.

near zero marginal costs and can take advantage of output-based tax incentives. In the organized markets, wind can nearly ensure that it will dispatch profitably whenever it is available, even if it bids into the market at less than zero.[44]

Distributed solar is largely guaranteed to displace other resources today because it is typically treated as a reduction of load, rather than as a generation resource that can be dispatched or curtailed. Electric cooperatives currently have nearly 240 megawatts (MW) of solar capacity online or on the drawing board across the country (see Figure 2.2.).

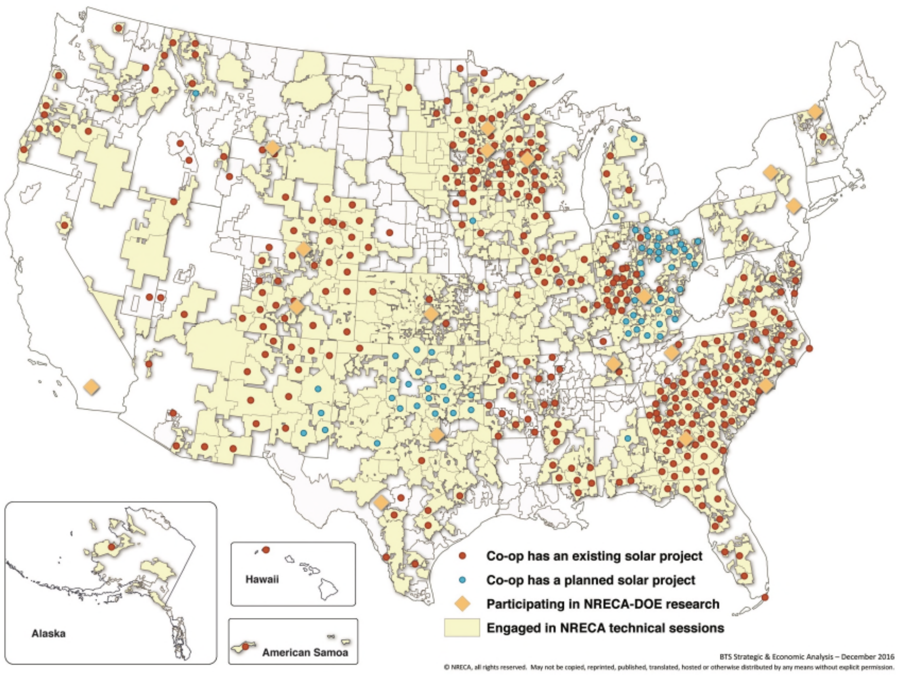

Figure 2.2. Rural Electric Cooperatives' Participation in Solar.

That increase in variable generation and decrease in fossil generation is changing the engineering of the system. Because wind and solar generators have little or no inertia, at high penetration they may make it harder for operators to manage voltage and thus maintain system stability. Because wind and solar generators had not originally been obligated to offer reactive power, and because they are not necessarily located where reactive power is needed, their increased deployment levels also may make it harder for system operators to meet the system's reactive power requirements. And because wind and solar output is variable, and because those variations do not necessarily match changes in load, the increased penetration of these resources puts more pressure on system operators to obtain the ramping resources required to keep load and generation in balance. This

[44] Variable generators' preferred place in the stack reduces risk for investors and thus further contributes to increased investment in wind and solar even in parts of the country that have more than sufficient energy and capacity available.

problem can be particularly acute where the variable resources displace in the commitment and dispatch stacks the very resources required to provide these essential reliability services.

In those parts of the country with the greatest penetration levels of variable generation, organized markets may need to develop new or amended ancillary services to ensure that they have access to the essential reliability services they need to manage the system reliably. Whether through the addition of additional ancillary services or though other market design adjustments, it will be critical that those market changes provide sufficient revenue to the generators that can provide those services to compensate utilities and other generating plant operators. We have already seen challenges in Texas, where fast ramping resources are being called upon regularly, with multiple starts and stops per day, without the compensation required to cover the maintenance costs such use imposes on the generator.

On the other hand, it will be important that the market design changes made to attract and compensate these new services are carefully targeted to those who provide the needed value so as not to unduly increase costs to utilities and their consumers. Poorly targeted changes to the market designs could unnecessarily increase costs to consumers by increasing revenues to generators not providing essential reliability services as well as to those who do.

The transition of the generation portfolio towards variable generation is also increasing the importance of long-term bilateral contracts and retail consumer relationships.

Rising levels of variable generation are exacerbating the already increasing spread between the cost of energy and the cost of power, both in organized market regions and the rest of the country.

With zero-marginal cost variable generation and very low-cost gas generation on the margin, energy prices — the cost of delivered kilowatt hours in real time — are often very low. For many hours, those prices can be negative.

The cost of power, however, has not fallen as fast as the cost of energy. As discussed above, utilities do not merely provide consumers with energy — kilowatt-hours — whenever it is available, at whatever it costs to generate at the time. Rather, utilities ensure consumers safe, reliable, affordable and environmentally sustainable electric service at reasonably predictable rates. That requires an investment in wires, communications, control systems, generation resources that will be available when the wind does not blow and the sun does not shine, generators that can ramp quickly in response to load changes and changes in variable generation, and generation that can provide essential reliability services, including reserves, reactive power, inertia and black start capability. It requires investment in generation that is out of market today because it meets climate goals or provides a physical hedge against future swings in fuel costs. It may require investment in financial hedges as well. It may require investment in firm fuel supplies, firm fuel delivery, or both, even for generation resources that may not be needed often. Those costs — all those that must be incurred to provide consumers the power they want — are not reflected in the real-time energy prices in the organized markets, but they must be recovered if consumers are to receive the service they expect.

In traditionally regulated states operating outside of the Eastern RTOs, this challenge can be addressed by utilities and regulators. If regulators (state public utility commissions, public power utility governing bodies, and cooperative boards) believe that costs have been prudently incurred, these costs can be included in rates charged to consumers. The process does become politically more difficult as the spread between the cost of energy and the cost of power gets larger. Seeing the low marginal costs of variable generation and natural gas, consumers and regulators may expect rates to drop more than they do. It may become harder for utilities to obtain the rate increases they need to maintain service at the level they have in the past. This is especially difficult for utilities operating adjacent to competitive systems or competitive states where the cost differential is more obvious. If so, they may have to work harder to educate consumers and regulators about the costs of providing service and the costs of different policy and service preferences. Or they may have to reprioritize and increase their pursuit of the short-term energy cost savings available today, while de-emphasizing the long-term price stability and reliability benefits that come from investments in a broader resource portfolio.

In restructured states and in the organized markets operated by the Eastern RTOs, the challenge presented by the spread between power and energy costs is more difficult. As the costs of energy decline *vis-à-vis* the cost of power, those competitive retail LSEs that simply pass through the cost of energy purchased from the organized markets have a competitive advantage over those that seek to manage a more diverse portfolio that is designed to serve longer-term interests and non-price values such as environmental sustainability. Similarly, competitive generation suppliers have no economic interest in making investments that could put them out-of-the-money in the competitive generation markets. Those competitive suppliers, for example, that operate peaking generators would be acting against their financial interests if they were to invest in the gas pipeline capacity required to ensure they have the gas they need to operate reliably during a few peak hours each year. Utilities and states in those markets have to become more creative if the consumers they represent are interested in more than low rates.

The economic challenges faced by nuclear generators in PJM and New York arise from this same disparity between the cost of energy and the cost of power. Those nuclear plants are reliable, produce no air emissions including carbon dioxide, and have relatively low and stable fuel costs. Those are the very traits that have led the Tennessee Valley Authority and utilities in the Southeast to invest in new nuclear generation. Nevertheless, these plants are uneconomic to operate in a very low-cost organized market environment, where variable generation and low-cost gas are setting the market clearing price.

Both New York and Illinois are trying to address those challenges by finding alternative means to compensate the nuclear generators for the value they provide to the electric system and to consumers. Yet, both are subject to legal challenge by plaintiffs who argue that those "out-of-market" subsidies undermine the effective workings of the organized markets and thus are preempted by the Federal Power Act.

Just as the organized market design in the Eastern RTOs interferes with state efforts to preserve certain existing resources and promote new diversified resource investments that serve multiple policy goals, so also does it interfere with those state efforts to address the disparity between the cost of energy and the cost of power. And the same solution is needed for both challenges.

Conclusion

The organized markets must be recognized as a tool to enable utilities and LSEs to meet their varied consumer, business and policy goals more efficiently. The organized markets must be residual to investments made by utilities and states. The organized markets must facilitate and provide efficient incentives for utilities and non-utility generators to contract long term in the wholesale markets. The organized markets must recognize that retail consumers' long-term support for the resources that meet their needs provide efficient and critical financial support for investment in not just "enough" new resources but in the "right" new resources. The organized markets should recognize that state policy requirements — and not just competitive purchasing decisions — permit consumers to help direct new investment.

It is important to remember that capacity is not fungible. Simply put, not all megawatts of capacity are created equal. LSEs, states and local regulatory bodies may have excellent policy reasons for preferring to assemble a diverse ("all-of-the-above") portfolio of generation and demand-side resources to serve retail electric needs.

The policy concerns that might lead LSEs and state and local regulatory bodies to favor local generation over distant generation; newer, more efficient resources over older, less efficient ones; lower-emitting resources over higher-emitting resources, etc., are completely legitimate. Federal policymakers should respect and honor them. Rules imposed in the organized markets to protect prices under administrative capacity procurement constructs should not erect barriers to meeting such policy goals.

Capacity surpluses can no longer be taken for granted; new resources will have to be developed to comply with new (and existing) environmental regulations. At such a time, long-term contracting and self-supply generation should be encouraged and supported, rather than being considered an "out-of-market" subsidy. Centrally-organized market rules that effectively penalize long-term contracting and self-supply should be reformed.

> ***The horse — consumers and the utilities and regulators that represent them — should be permitted to pull the cart in the direction they want to go. The cart — the organized markets — should not dictate that direction and should not put on the brakes if consumers are asking for something the organized markets cannot today provide.***

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3. Market Reform to Facilitate Public Policies and a Changing Resource Mix

By Allison Clements, Natural Resources Defense Council

Introduction

Wholesale Market Origins

Under the Federal Power Act, the Federal Energy Regulatory Commission (FERC) is responsible for ensuring that the rates for wholesale sales of electricity are "just and reasonable" and that they do not provide undue preference or discrimination.[45] Wholesale sales are the sales of energy from wholesale sellers (power plant owners) to wholesale buyers — the investor- and publicly owned retail utilities that serve residential, commercial, industrial and agricultural customers, as well as other large consumers who buy power at the wholesale level instead of purchasing it through a retail utility. FERC is also responsible for the reliability of the transmission system[46] (see Figure 3.1.). These two areas of authority provide the basis for FERC's oversight of and perspective on wholesale market design.

For several decades, starting with passage of the Federal Power Act in 1935, FERC's area of authority was complex but relatively straightforward, involving regulation of vertically integrated (i.e., generation, transmission and distribution-owning) investor-owned utilities in their operation of and transactions related to the nation's high voltage transmission system. For the most part, vertically integrated utilities either owned generating facilities or directly purchased energy via power purchase agreements or other bilateral contracts.

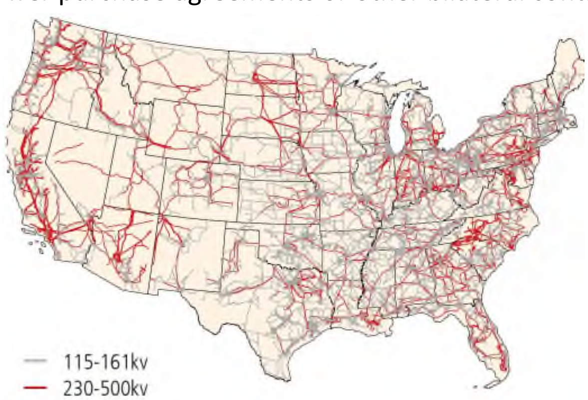

Figure 3.1 Federally Regulated Transmission Lines.
This map from the U.S. Department of Energy's Quadrennial Energy Review depicts the transmission lines across the country subject to FERC's authority.[47]

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[45] Federal Power Act, 16 U.S.C. Sections 824 *et seq.*, Sections 205 and 206.
[46] Energy Policy Act of 2005, Pub. L. No. 109-58, Sections 1261 et seq., 119 Stat. 594 (2005).
[47] http://energy.gov/sites/prod/files/2015/08/f25/QER%20Chapter%20III%20Electricity%20April%202015.pdf at 3-23.

The last several decades have brought significant and varied change to the electric system at the local, state and federal levels. Starting as early as the 1960s, although sales continued to occur bilaterally, neighboring utilities informally and later formally began joining together to gain economic efficiencies by coordinating their power plant dispatch and sharing reserve power supply. FERC initially recognized the formation of these coordinated "power pools" and later encouraged more formal cooperation (and the establishment of competition) among utilities and independent power producers by opening access to the transmission system for competitors and encouraging the formation of independent system operators and regional grid transmission organizations, known as ISOs and RTOs.[48]

By this point, the Public Utility Regulatory Policies Act (PURPA) had already begun achieving the effect not only of encouraging renewable energy development, but also introducing competition from independent power producers (i.e., power plants owned by entities other than vertically integrated utilities) into wholesale power sales.[49] FERC's continuing encouragement of centrally organized markets in ISOs and RTOs cemented the agency's support for wholesale competition. Since that time, centrally organized markets have come into existence in several regions across the country.

In 2002, FERC engaged in a failed attempt to impose a standard market design across all regions of the country.[50] Since that time, the agency has not attempted to impose any similar standard market structure and instead provides for significant regional flexibility. As a result, a comparison of wholesale market structures across the existing RTOs and ISOs reflects significant variability. The variability is of course subject to certain common standards. For example, markets must demonstrate sufficient market monitoring, and energy markets must allow for participation by demand response resources.

In regions where they exist, today's wholesale markets take three forms:

1. *Energy markets*, pursuant to which wholesale sales of electricity take place
2. *Capacity markets*, designed to ensure future resource availability sufficient to meet predicted customer demand by committing to pay resources for their availability one to three years before that availability is needed
3. *Ancillary service markets*, which provide:

[48] Order 888. Promoting Wholesale Competition Through Open Access; Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities (1996). https://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8-00w.txt; Order 2000, Regional Transmission Organizations. 1999. http://www.ferc.gov/legal/maj-ord-reg/land-docs/RM99-2A.pdf.
[49] Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117.
[50] Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, 67 Fed. Reg. 55,452, Docket No. RM01-12-000 (Aug. 29, 2002), Order Terminating Proceeding (July 19, 2005).

a. Reserves — Resources that have not cleared in the energy market but stand ready to produce in case demand is unexpectedly high or a power plant or transmission line experiences an unanticipated outage
b. Grid services like frequency regulation and frequency response — To balance supply and demand on the grid in the second-to-second and minute-to-minute time frame[51]

FERC has not mandated or even explicitly encouraged capacity market development in the centrally organized market regions. Regions that have developed full capacity markets (e.g., PJM, ISO-NE) correlate with a high percentage of restructured states in the region — meaning states that have ended utility monopolies and introduced competition into the retail sale of electricity. Both capacity market regions and those regions with residual or more supplementary capacity market constructs (e.g., MISO, CAISO) demonstrate significant variation in design and operations. All regions have some forms of ancillary service markets — at least spinning and non-spinning reserves — but they vary in number and form (see * Note that Texas' transmission grid is not interconnected with the rest of the country's
transmission system and is not regulated by FERC.
Figure 3.2.).

	Day-Ahead and Real-Time Energy	*Full Capacity Market*	*Residual Market/Resource Adequacy Construct*	*Auction-Style Ancillary Service Markets*
ISO-NE	X	X		X
NYISO	X		X	X
PJM	X	X		X
MISO	X		X	X
SPP	X			X
CAISO	X		X	X
ERCOT*	X			X

* Note that Texas' transmission grid is not interconnected with the rest of the country's transmission system and is not regulated by FERC.

Figure 3.2. Existing Regional Centrally-Organized Markets.
The regions differ not only in the types of wholesale markets that exist but also in the rules that govern each of the same market types.

[51] Order 888 originally established the ancillary services that all transmission-owning utilities were required to provide or procure on behalf of transmission customers. Those services include: (1) scheduling, system control and dispatch; (2) reactive supply and voltage control from generation service; (3) regulation and frequency response service; (4) energy imbalance service; (5) operating reserve – synchronized reserve service; and (6) operating reserve – supplemental reserve service. All of the RTO and ISO regions have markets for reserves, and in recent years FERC has issued rules providing for competition in the provision of frequency regulation and frequency response.

Market and Policy Dynamics

In recent years, wholesale market designs have experienced growing pains related to a changing resource mix on both the supply and demand sides. On the supply side, market forces — in particular the abundant supply of low-cost natural gas — have rendered some existing fossil-fuel and nuclear resources uneconomic, leading to unit retirements or at least prolonged shutdowns.[52] As discussed in response to Question 3 further below, environmental regulations that have required investment in pollution-mitigating technologies have added to pressures on these increasingly uncompetitive generating resources, but have not been the singular or even central cause of their economic decline.[53] In addition, state renewable portfolio standards and federal tax incentives, together with decreasing technology costs and customer preferences, have led to significant increases in the amount of non-hydro renewable energy resources added to the electric system. Over the last decade, for example, solar power has experienced a 60 percent compound annual growth rate.[54] On the demand side, distributed energy resources (DERs) like energy efficiency, demand response, distributed solar generation, electric vehicles and other storage, and the smart grid hardware and software that facilitate their operation, have not only contributed to a national trend of flat or declining demand but also increased competition in the provision of energy, capacity and ancillary services at both the distribution and transmission system levels.

> ***[M]arket forces — in particular the abundant supply of low-cost natural gas — have rendered some existing fossil-fuel and nuclear resources uneconomic, leading to unit retirements or at least prolonged shutdowns. [...] [E]nvironmental regulations that have required investment in pollution-mitigating technologies have added to pressures on these increasingly uncompetitive generating resources, but have not been the singular or even central cause of their economic decline.***

Capacity markets were designed before these market dynamics came to exist, under a paradigm in which all megawatts were equal for purposes of ensuring resource adequacy. Perhaps more accurately, at least all generating resources were on or able to turn on in response to dispatcher

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52 Tierney, S. F. *The U.S. Coal Industry: Challenging Transitions in the 21st Century*. Analysis Group, Inc., at p. 1 (2016). http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/tierney%20-%20coal%20industry%20-%2021st%20century%20challenges%209-26-2016.pdf. This recent report points to a series of market drivers that have been underway since at least 2000, which have contributed to the decline of the coal industry, including "declining coal-mining productivity, shifts in global demand for coal, the shale-gas revolution which eroded coal's price advantage, the ever-increasing efficiency with which consumers use electricity, the overall flat demand in the power sector, recent cost reductions in renewable energy technology, and poor investments by a number of large coal companies."

53 See Tierney 2016, at p. 21.

54 See Solar Energy Industry Association. *Solar Industry Data*. http://www.seia.org/research-resources/solar-industry-data.

instructions. Generating unit outage rates and system load were largely predictable. Marginal fuels were always fossil.

In the new world, zero-marginal cost renewable resources are, in many cases, cheaper than fossil fueled generation. Although increasingly dispatchable, renewable resources have variable characteristics that are not only impacting capacity market rules and operation but threatening to render current capacity market constructs obsolete. Two specific examples of the incompatibility of current market design and the reality of the new resource mix may be instructive.

First, wind and solar power, as well as demand-side resources, are getting caught in the net of capacity market buyer-side mitigation rules.[55] Regions require that some resources, including renewable energy resources, meet "minimum offer price rules" (MOPR), market bid floors that are designed to prevent subsidized or otherwise low-cost new entrants into capacity markets from suppressing market clearing prices.[56] Renewable resources that are subject to these minimum offer rules may end up failing to clear the capacity market, thereby prohibiting valuation of the capacity that they are, in fact, contributing to the system. These minimum offer price rules may also make the cost of participating in wholesale demand response programs cost more and compel customers to choose between participation in wholesale and retail demand response programs, resulting in harm to both types of programs. Encouragingly, FERC recently has recognized as much in exempting demand-side resources from NYISO's minimum offer price rules.[57]

Then Chairman Bay provided a powerful case against buyer side mitigation in a concurrence accompanying a FERC order exempting demand-side resources from a minimum offer price rule in NYISO. He wrote:

> *The premise of the MOPR appears to be based on an idealized vision of markets free from the influence of public policies. But such a world does not exist, and it is impossible to mitigate our way to its creation. The fact of the matter is that all energy resources receive federal subsidies, and some resources have received subsidies for*

[55] Buyer-side mitigation rules are designed to "prevent[] [utility buyers] from acquiring 'uneconomic' capacity resources that will 'artificially' suppress clearing prices" in wholesale capacity markets. Morrison, J. "Capacity Markets, A Path Back to Resource Adequacy" *Energy Law Journal* 37:1. 2016. http://www.felj.org/sites/default/files/docs/elj371/18-1-60-Morrison_FINAL.pdf.

[56] Several variations on the rationale for protecting against the exercise of buyer-side market power have been used in the development of buyer-side mitigation rules and are described in detail in Morrison, J., *Energy Law Journal* 37:1 and Miller, Richard B., Neil H. Butterklee, and Margaret Comes. *"'Buyer-Side Mitigation' in Organized Capacity Markets: Time for a Change?" Energy Law Journa*l 33:449. 2012. For purposes of this discussion, it is worth noting the concern that state-subsidized resources, like renewable resources, can offer into the capacity market at below-market rates is largely that they distort (lower) market prices, and less that it is to the likely advantage of the state-subsidized resource owners.

[57] See *NY PSC et al. v. NYISO*. Order Granting Complaint in Part and Denying in Part, 158 FERC ¶ 61,137. 2017.

decades. Yet the MOPR is only concerned with state subsidies, not federal ones, though both can have a similar impact on markets. And even with respect to state conduct, the MOPR's review is incomplete at best. The MOPR does not mitigate the wholesale offers of utilities located in vertically integrated states. Nor does the MOPR examine whether existing resources have previously benefited from a state subsidy. In short, the MOPR suffers from a troubling lack of coherence that calls into question the soundness of its underlying rationale.[58]

[S]ome capacity market rules are making discriminatory determinations about which resources can participate in capacity markets. In PJM, for example, new capacity market rules require resources to be available to generate power (or reduce the need to generate power, in the case of demand response and other DERs) all day, every day, all year. Wind and solar resources, and demand response and other DERs that can provide capacity sometimes but not all the time, are effectively precluded from participating in PJM's capacity market starting in 2017 for delivery year 2020–2021. As a result, PJM will over-procure qualifying capacity performance resources. This over-procurement will be very expensive.

Buyer-side mitigation through the use of minimum offer price rules is not an effective route to address the impact of state policies that subsidized preferred resources on wholesale capacity markets.

Second, in attempt to preserve the current capacity construct, some regions' rules are making discriminatory determinations about which resources can participate in capacity markets. In PJM, for example, new capacity market rules require resources to be available to generate power (or reduce the need to generate power, in the case of demand response and other DERs) all day, every day, all year.[59] Wind and solar resources, and demand response and other DERs that can provide capacity sometimes but not all the time, are effectively precluded from participating in PJM's capacity market starting in 2017 for delivery year 2020–2021.[60] As a result,

[58] Ibid. The concurrence did note a limited exception to the case against buyer side mitigation in the rare cases that there is actual preemption of federal authority over wholesale rates occurring.

[59] See Chen, J. *Auction Shows Mid-Atlantic/Midwest Consumers Will Pay More and For Dirtier Electricity Under New Rule*. 2015. https://www.nrdc.org/experts/jennifer-chen/auction-shows-mid-atlanticmidwest-consumers-will-pay-more-and-dirtier.

[60] PJM has proposed rules that would allow aggregation of demand-side and variable resources to qualify as capacity performance resources, but those rules have been challenged by many parties at FERC, including a protest useful in explaining the impact of the proposed rules on demand-side resources by the Advanced Energy Management Alliance, Natural Resources Defense Council, Rockland Electric Company, Sierra Club and Environmental Law & Policy Center. See *PJM Interconnection, L.L.C.*, Docket No. ER17-367 (2016). https://www.dropbox.com/s/os2q9x14xtutg4i/2017-02-13%20NRDC-ELPC%20Protest%20in%20ER17-367%20%28AEMA%20Complaint%29?dl=0.
Variable resources can still bid in as though they meet the annual performance requirements, but will be penalized for failure to respond in instances they are unable to do so.

PJM will over-procure qualifying capacity performance resources. This over-procurement will be very expensive. If history is a guide, maintaining current capacity market design and using only capacity performance-qualifying resources could amount to as much as $5 billion in increased costs to customers in just one delivery year.[61]

These examples are representative of the increasing disconnect between current market design and the changes that technical advances, public policies and market forces have brought to bear on the nation's electric system. A system moving away from sole reliance on central-station fossil fuel and nuclear power to one that prominently features wind and solar power requires an evolving view of resource adequacy and reliability, the services that the system needs to operate reliably, and various resources' contributions to those services.

With this background, I respond to the four questions this report addresses.

1. **Are today's centrally-organized market designs adequate to accommodate state public policy goals, and what potential design changes would further enable deployment of resources that achieve the goals of reliability, affordability and resource mix?**

The increasing tension between some public policies and wholesale market design may threaten reliability and will certainly increase costs to consumers. Significant reform is necessary to bring wholesale market design into alignment with the reality of our country's public policy landscape and evolving electricity resource mix.

Existing wholesale energy and capacity markets have proven successful, to varying degrees, in achieving their intended purposes: facilitating competition in the sale of energy and ensuring resource adequacy (i.e., enough megawatts of generating facilities will be online and available to meet predicted future customer demand, typically looking one to three years ahead). Consideration of the markets' success in accommodating public policies must be more nuanced. The markets themselves are results of public policy implementation — specifically FERC's policies to open the transmission system to competition and the encouragement of regional transmission organizations, among others.[62] The markets have also proven capable of facilitating market-oriented policies like, for example, the Regional Greenhouse Gas Initiative (RGGI), which involves inclusion in energy market bids of RGGI allowance prices by generators participating in RGGI, as well as policies imposing

[61] Monitoring Analytics. *The Independent Market Monitor for PJM.* An analysis of the 2019/2020 RPM Base Residual Auction is at pp. 12–14. 2016. http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf.

[62] See, e.g., Order 888. https://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8-00w.txt, and Order 2000, http://www.ferc.gov/legal/maj-ord-reg/land-docs/RM99-2A.pdf.

operational limitations, like dispatch restrictions on fossil-fueled generating units on high electricity demand days under state clean air policy.

Energy and capacity markets, however, were not designed to facilitate state energy policies like renewable portfolio standards or energy efficiency resource standards, or emerging state reliability-related preferred resource policies. Even federal tax policy is contributing to the changing resource mix. The increasing tension between some public policies and wholesale market design may threaten reliability and will certainly increase costs to consumers. Significant reform is necessary to bring wholesale market design into alignment with the reality of our country's public policy landscape and evolving electricity resource mix.

[A]n increasingly interconnected system involving choices of preferred resources by states, as well as DERs that interconnect to the distribution system but have the ability to contribute to system needs at both the distribution and transmission levels, implicate both state utility commission and FERC regulation. These interactions have caused growing pains and injected uncertainty into what was once considered a "bright" dividing line between state and federal authority over the electric system.

The technology, market and policy forces that have contributed to increasing amounts of renewable energy and the emergence of DERs have created a regulatory context in which the law is lagging behind the reality of a changing electric grid. At least two kinds of tensions exist.

First, laws clearly within the domain of the states or FERC are outdated. Wholesale market rules, specifically, were designed around central-station, fully dispatchable power plants and predictable, relatively inflexible load shapes. Some of these rules have been updated, and others must be updated to apply to variable resources like wind and solar power, as well as DERs.

Second, an increasingly interconnected system involving choices of preferred resources by states, as well as DERs that interconnect to the distribution system but have the ability to contribute to system needs at both the distribution and transmission levels, implicate both state utility commission and FERC regulation. These interactions have caused growing pains and injected uncertainty into what was once considered a "bright" dividing line between state and federal authority over the electric system.[63]

[63] See Dennis, Jeffery S., Suedeen G. Kelly, Robert R. Nordhaus, and Douglas W. Smith. *Federal/State Jurisdictional Split: Implications for Emerging Electricity Technologies.* Prepared for Lawrence Berkeley National Laboratory. December 2016. LBNL-1006675. https://emp.lbl.gov/sites/all/files/lbnl-1006675.pdf.

Three recent Supreme Court cases, which have received significant attention in the energy regulatory sphere, have provided instructive guideposts in understanding the division and overlap of state and FERC authority and jurisdiction.[64] The decisions together tell us a few things. States and FERC each have the ability to regulate demand response (and other demand-side resources) as long as they are targeting the resources' participation in activities that fall within their traditional areas of authority.[65] Also, states have the authority to continue preferred resource procurement, but must do so without targeting the wholesale rates at which power from preferred resources will be sold, as those rates remain subject to FERC jurisdiction.[66] Of course questions about the contours of the state-federal regulatory divide remain, but the decisions, none of which were close calls for the Justices, represent an understanding by the Supreme Court that the electric grid is increasingly interconnected and that the states and FERC must work in the spirit of cooperative federalism to effectively regulate.[67]

State and federal policies mandating renewable energy, energy efficiency, demand response or other DER development increase the amount of energy, capacity and ancillary additions available to the system — often at zero fuel cost. Failure to count the existence of these resources (in load forecasting), allow for their participation in markets and fully value that participation will increase wholesale costs unnecessarily.

With these current jurisdictional guideposts in place, a premise to suggesting principles to guide market design reform is the recognition that FERC has the authority and obligation to ensure that wholesale markets accommodate state and federal public policies. FERC has an obligation to ensure just and reasonable rates for wholesale power sales, and existing and emerging state and federal public policies implicate those rates. State and federal policies mandating renewable energy, energy efficiency, demand response or other DER development increase the amount of energy, capacity and ancillary additions available to the system — often at zero fuel cost. Failure to count the existence of these resources (in

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64 *FERC v. Electric Power Supply Association.* 136 S.Ct. 760 (2016) ("EPSA"), https://www.supremecourt.gov/opinions/15pdf/14-840_diff_pok0.pdf, with commentary at https://www.nrdc.org/experts/allison-clements/us-supreme-court-decision-demand-response-forces-awaken; *Hughes v. Talen Energy Marketing, LLC*. 136 S.Ct. 1288. 2016. ("Hughes"), https://www.supremecourt.gov/opinions/15pdf/14-614_k5fm.pdf, with commentary at https://www.nrdc.org/experts/allison-clements/supreme-court-decision-striking-down-maryland-program-contains-good-news; *Oneok, Inc. v. Learjet, Inc.* Slip Op. No. 13–271. 2015. ("Oneok"), https://www.supremecourt.gov/opinions/14pdf/13-271_j4ek.pdf.

65 See *EPSA*, 136 S.Ct. 760; *Oneok* at p. 11.

66 See *Hughes*, 136 S.Ct. 1288 at p. 14–15.

67 *See Hughes*, 136 S.Ct. 1288 (Sotomayor, J., concurring).

load forecasting) allow for their participation in markets and fully value that participation will increase wholesale costs unnecessarily.

In the context of transmission system planning, another area of FERC's authority under the Federal Power Act, FERC has recognized the need to discipline transmission-owning utilities' planning and investments by consideration of public policies. With the U.S. Court of Appeals for the D.C. Circuit in full accord, FERC reasoned that transmission planning must contemplate grid needs driven by public policies, so that cost-effective system planning decisions can be made to facilitate those policies.[68] The utilities, at least in their transmission-owning capacity, are not responsible for determining how to comply with state and federal environmental and energy policies outside of FERC's jurisdiction. As FERC-jurisdictional entities, however, they must be mindful of FERC's obligation to ensure just and reasonable rates and non-discriminatory access. In the transmission planning context, transmission owners should plan to effectuate the compliance path chosen by the entities that are responsible for state and federal environmental compliance cost effectively (assuming those compliance paths drive grid needs). For example, if Illinois decided it wanted to satisfy its renewable energy standard with wind resources from North Dakota, FERC has made clear it is the Mid-Continent Independent System Operator's (MISO's) responsibility to consider and plan for transmission investments, and alternatives to transmission investments, which most cost-effectively address any grid needs related to transporting that wind. It is also MISO's responsibility to plan for any system conditions or requirements related to the planned retirement of fossil-fueled generating units, by considering the full range of non-transmission alternatives (e.g., demand response, targeted energy efficiency, other DERs) and transmission options that can most cost-effectively address those conditions.

In the wholesale market context, FERC has taken specific actions that recognize public policies implicate markets, but has not taken as systematic an approach as it has with system planning. For example, most recently FERC has proposed that wholesale markets ensure the ability of energy storage resources and DERs to participate.[69] This rule recognizes that public policies like California's energy storage mandate[70] and market forces have led to increases in storage availability. FERC has not gone as far as suggesting that all wholesale market design should contemplate the impacts of public policy. However, it is hard to deny that federal and especially state public policy choices are having impacts on, or have the potential to impact, markets in manners that, if not contemplated and incorporated into market rules, may distort fair market outcomes. This result has already played out in several

[68] *South Carolina Public Service Authority v. FERC*. No. 12-1232 at p. 82 (2014). https://www.ferc.gov/media/statements-speeches/lafleur/2014/08-15-14-lafleur.pdf.
[69] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*. 157 FERC ¶ 61,121 (2016). https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-1.pdf.
[70] The mandate requires the state's investor-owned utilities to procure a combined 1,325 MW of storage by 2020. See http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M079/K171/79171502.PDF.

contexts. In the *Hughes* decision referenced above, Maryland's procurement program was invalidated on legal grounds, but even short of the legal problems, other decisions by states to require procurement of preferred resources have run up against wholesale market rules that prohibit full valuation of the states' resource choices.[71]

This policy and legal context sets the stage for finding solutions to address tensions emerging between public policies and wholesale market approaches to maintaining just and reasonable prices while ensuring and even improving near-term system reliability. While all of these issues can be addressed, significant work remains to achieve reform across the regions in a manner that provides regions flexibility to facilitate their own resource mixes while ensuring an affordable and reliable electric grid. Of course, FERC's authority to require the consideration of public policies in market design must be exercised within the jurisdictional realities understood via the Supreme Court cases discussed above, as well as within the context of remaining uncertainties. Building on this introductory context, following are principles that should guide necessary market reform.

Incorporating Public Policies — Proposed Principles for Market Reform

Well-functioning wholesale markets that facilitate, but do not supplant, environmental and energy-related local, state and federal public policies are critical to ensuring FERC satisfies its just and reasonable rate obligations, and that ultimately all types of customers — not only wholesale but residential, commercial, industrial, governmental and agricultural retail customers — experience reliable and affordable electricity service. As discussed above, today's markets are not designed to facilitate the full suite of policies that implicate the transmission system, and significant reform is necessary to rectify incongruences in market designs. In order to evolve wholesale markets to the point of effective policy recognition and facilitation — and as a result maintain just and reasonable rates — Natural Resources Defense Council recommends five principles that should guide efforts at reform.

First, wholesale market rules should do no harm to existing local, state and federal environmental policies. FERC is not an environmental regulator and has no mandate to develop substantive energy or environmental policies intended to pick winners or losers in the fuel source competition. However, a changing resource mix caused at least in part by policy, along with the reality that sellers and buyers of wholesale energy subject to FERC's authority are also charged with implementing environmental policies (for example, coal generating unit owners subject to FERC's jurisdiction for wholesale market participation are also responsible for installing scrubbers to capture toxic pollutants as required by the U.S.

[71] See Morrison 2016 at p. 22 ("several FERC commissioners have acknowledged the legitimacy of the state goals, and have expressed some angst at the impact that the capacity construct rules have had on state policies, the rules have consistently placed supposed market efficiency above state policy").

EPA's Mercury and Air Toxics Standards),[72] have created new intersections of energy and environmental policy that must be addressed in the context of market reform.

FERC must ensure just and reasonable rates and avoid undue discrimination in the wholesale sale of power. As a result, it is the agency's role to ensure that regional markets facilitate public policies by, for example, allowing for market participants to include in their energy offers the costs of participation in the Regional Greenhouse Gas Initiative in the Northeast. In contrast, it would not be FERC's role to approve the rules for carbon credit auctions or alternative carbon trading regimes. However, FERC could approve a direct carbon adder to energy market dispatch if states or the federal government chose that policy approach. Discussions about the potential for a federal carbon tax or region-specific carbon adders will challenge jurisdictional boundaries, but should not be discounted for that reason. Such discussions should embrace this do-no-harm principle.[73] Further, FERC should avoid designing market rules or approving regional proposals that implicate states' rights to procure their own desired resource mix, even if a feasible legal pathway exists to justifying the rules.

Second, to the extent capacity markets continue to serve as the basis for resource adequacy in some regions, they must recognize and value the contributions of all supply- and demand-side resources to resource adequacy, including resources that do not participate in regional capacity markets or constructs.

- Load forecasts should capture all existing and planned energy efficiency and other DERs. Capacity procurement is based on regional forecasts of future demand for electricity. Load forecasts that do not capture all existing demand-side resources, like energy efficiency and distributed generation, may lead to over-predictions about future demand and an ensuing call for more supply-side resources than actually needed.[74] For example, PJM was able to lower its forecast by 4,700 megawatts (MW) over four years by attempting to count existing energy efficiency within its states, which according to NRDC's estimates equates to roughly $2.4 billion in customer savings per year.[75] FERC should require regional load forecasts to capture these demand resources towards more

[72] *Mercury and Air Toxics Standards*. 77 Fed. Reg. 9304 (2012).
[73] This chapter does not take a position on whether a carbon adder is an important feature of future energy or capacity markets. The concept holds promise, but significant legal and market design analysis of any specific proposal would be required to ensure the proposal adheres to the principles suggested here and is otherwise beneficial on the merits. For an excellent distillation of FERC's authority related to the pricing of carbon in markets, see Peskoe, A., Senior Fellow, Harvard Law School Environmental Law Program Policy Initiative, *Integrating Markets and Public Policy in New England Wholesale Electricity Markets: Legal Analysis* (2016) (discussion draft). http://environment.law.harvard.edu/wp-content/uploads/2016/10/IMAPP-Memo-Harvard-Environmental-Policy-Initiative-10-27-16.pdf.
[74] See Clements, A. DERs AND REGIONAL LOAD FORECASTING: Getting Full Bang for Our Bucks. Natural Resources Defense Council. 2016. https://www.nrdc.org/experts/allison-clements/small-power-big-grid-part-2.
[75] See Chen, J. What's the (Demand) Forecast? More Energy Efficiency on the Radar. Natural Resources Defense Council. 2015. https://www.nrdc.org/experts/jennifer-chen/whats-demand-forecast-more-energy-efficiency-radar.

accurate load forecasts. A failure to enact such a requirement risks over-forecasting and over-procurement, which in turn risks violating FERC's obligation to ensure just and reasonable rates.

- Also discussed above, capacity market or construct rules should allow for all types of resources that can provide capacity to participate, even if that capacity does not come in the form of traditional, baseload or peaking, dispatchable nuclear and fossil-fuel generation. If a demand response resource can participate for 10 periods each summer but not every day year-round, capacity market rules should continue to facilitate that summer participation. Facilitating a diverse resource mix likely means expanding beyond a single capacity product-based market. The California Independent System Operator (CAISO) has made progress in designing rules that allow for expanded resource participation. It updates its capacity factors monthly and has developed a flexible capacity requirement to address ramping issues on its system due to high penetrations of solar coming on and offline throughout the day.[76]

It is not clear that longer commitment periods that secure capacity more than three years in advance are either a substantively appropriate or politically feasible mechanism for securing sufficient resource commitment.

It is not clear that longer commitment periods that secure capacity more than three years in advance are either a substantively appropriate or politically feasible mechanism for securing sufficient resource commitment. Ensuring a revenue stream five or even 10 years forward would provide investment certainty that can facilitate the self-financing or debt-financing of new power plant construction (and even, perhaps, the construction of transmission lines related to the existence of those power plants that may not qualify for regulated cost recovery). However, the same facilitation does not hold true for demand response and other "shorter lead time" DERs for which longer-term certainty is a barrier to capacity market participation.[77] For these demand-side resources that aggregate customer participation and therefore are vulnerable to customers moving or exiting their programs with little notice, the ability to ensure resource availability three years forward is already a

[76] See FERC. Order on Tariff Revisions. 156 FERC ¶ 61,226. https://www.caiso.com/Documents/Sep26_2016_OrderAcceptingFlexibleRampingProductTariffAmendment_ER16-2023.pdf.

[77] See, e.g., comments of Viridity Energy, Inc. in FERC Docket No. AD13-7. *Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators,* at p. 4 ("[B]ringing short lead time resources into a three-year forward auction loses the advantage of flexibility to use short lead time resources to meet sudden increases in the need for capacity. Second, and more problematic, procuring these resources several years in advance of the delivery year highlights the uncertainty that accompanies another key characteristic of demand resources: the customer's flexibility to exit the capacity market quickly and easily.")

significant existing challenge.[78] Adding years to the period demand response providers must guarantee availability would make market participation that much more difficult. (The exceptions to concerns over increased commitment periods for DERs are the several types of storage that face higher upfront costs than other DERs and can provide limited duration capacity with more predictability looking forward.)

Locking in longer-term forward commitment periods for capacity market participation has the potential to exacerbate the problem, described in response to Question 4 below, of rewarding the value of fossil fuel and nuclear power plants to the detriment of cheaper, flexible DER resources and other potential market-based services.[79] The more appropriate inquiry is whether a transmission grid with increasing penetrations of low-cost, carbon-free renewable power is more cost-effectively operated by doubling down on capacity markets that do not allow all resources that can provide valuable grid services to compete, or by reevaluating market design to ensure the grid provides the flexibility necessary to complement the reality of today and tomorrow's grid.[80] As described next, NRDC believes in the latter approach.

Third, market rules should provide a platform that allows all technically capable resources to participate and should fully compensate resources for the wholesale services they provide. Beyond allowing for participation in capacity markets or other procurement constructs, all markets should remove barriers to participation by resources that are technically capable of providing the relevant service, whether it is energy or ancillary services.

CAISO has led the way in providing rules that allow for the aggregation of DERs for participation in its wholesale energy and ancillary service markets.[81] FERC's recently proposed rule on incorporating energy storage and DERs into wholesale markets also is an important step in this regard and holds broad and significant potential to transform

[78] See Id., at p. 5 (describing the reasons for uncertainty in more detail and citing EnerNOC, Inc., Annual Report on Form 10-K to the Securities and Exchange Commission, for the Fiscal Year ended December 31, 2012 at pp. 40–41).
[79] See comments of the Regulatory Assistance Project, in FERC Docket No. AD13-7, *Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators,* at p. 3 ("Where single-product centralized capacity markets have been introduced they have thrown a lifeline indiscriminately to capacity resources without consideration for other equally important factors determining whether or not adequate supply is likely to be available at all times and at least cost.").
[80] Flexibility is the grid characteristic that assures it can balance rapidly fluctuating supply and demand. Although most variability between supply and demand, even on systems with a significant amount of renewable energy penetration, is a result of inaccuracies in short-term load forecasts, "[v]ariations from renewable energy forecasts and normal variability of wind and solar output due to local changes in cloud cover and wind speed can also contribute to the normal changes that must be balanced." Bradley, M. J. *Powering into the Future: Renewable Energy and Reliability.* 2017. http://www.mjbradley.com/reports/powering-future-renewable-energy-grid-reliability. The flexibility market products developed by MISO and CAISO and described in response to Question 4 below, offer good initial examples of market design adjustments to facilitate their evolving resource mixes.
[81] See CAISO. Distributed energy resource provider. https://www.caiso.com/participate/Pages/DistributedEnergyResourceProvider/Default.aspx.

wholesale market design. It does, however, fall short in one important respect.[82] In an attempt to "ensure that there is no duplication of compensation" for DERs, the proposed rule would prohibit from wholesale market participation those DERs that are receiving compensation for participating in retail net metering programs or other retail-level DER programs (or markets).[83] A more narrowly tailored approach — adherence to a principle that no resource should be paid twice for the same service — would address FERC's legitimate concern while avoiding unnecessary barriers to DER market participation design.

The New York Public Service Commission's (PSC's) Reforming the Energy Vision proceedings have contributed to the focus of the PSC and New York Independent System Operator (NYISO) on how DERs can participate in wholesale and retail markets. NYISO's Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets, in particular, provides a model for regions to further thinking on potential mechanisms for successful DER integration.[84]

Removing barriers to DER wholesale market participation, without hindering the ability to participate in retail grid service programs, will allow both restructured, retail market-oriented states like New York, and other states that plan to take very different approaches from New York, to facilitate DER wholesale market participation.

Fourth, FERC should ensure that wholesale markets provide the set of services necessary to facilitate the evolving electric grid and avoid locking in an outdated view of grid reliability. This principle is addressed in response to Question 4, further below.

Fifth, market rule changes should be subject to stakeholder review and input. Wholesale market design issues are complex and involve significant technical and economic considerations. In order to effectively participate in RTO and ISO proceedings considering material market rule changes, even the most seasoned of RTO and ISO stakeholders need education and, often, expert assistance. Order 2000's encouragement of RTOs and ISOs

FERC should consider review of RTO and ISO governance and decision-making to ensure that regions actually engage in thorough and transparent stakeholder processes when considering material market rule changes, including education as necessary.

[82] See Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators. 157 FERC ¶ 61,121 (2016), https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-1.pdf.
[83] Id. at ¶ 134.
[84] NYISO. *Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets.* 2017. http://www.nyiso.com/public/webdocs/markets_operations/market_data/demand_response/Distributed_Energy_Resources/Distributed_Energy_Resources_Roadmap.pdf?__cldee=YWRhbS5ldmFuc0BkcHMubnkuZ292&recipientid=contact-d8d002c31d2fe5119404005056810dcf-2a695cd5b37e48d19e7ab0e0a2cd4ce9&esid=d1ddd383-62e9-e611-9424-005056815c52.

contained principles intended to ensure independence and transparency on the part of the grid operators.[85] While this paper does not discuss the significant need for RTO and ISO governance reform, it is important to note that in practice stakeholder processes in RTOs and ISOs often fail to reflect these principles. The interests of incumbent transmission-owning utilities and wholesale generators often hold outsized influence to the detriment of other stakeholder interests. FERC should consider review of RTO and ISO governance and decision-making to ensure that regions actually engage in thorough and transparent stakeholder processes when considering material market rule changes, including education as necessary. Except under extraordinary circumstances, RTOs and ISOs should be prohibited from accelerating regular time frames for stakeholder consideration of material market rule changes. In addition, FERC should be skeptical of efforts by RTOs and ISOs to push through market rule changes that are opposed by a material number of involved stakeholder groups.

Establishment of a set of principles like the ones provided here offers an approach to FERC, RTOs and ISOs, and interested stakeholders to reform market rules in a manner that more effectively incorporates the full set of state public policies that implicate the transmission system while maintaining the ability of regions to develop solutions specific to their circumstances.

2. What are the market impacts of environmental regulations further constraining the deployment of fossil fuel resources?

It is important first to recognize that market factors — most importantly the abundance of domestic, low-cost natural gas — are the paramount cost-based drivers today constraining the deployment of new coal- and oil-fired resources and making existing fossil fuel and nuclear resources increasingly uneconomic.[86] The history of regulations to protect clean air and water have contributed to increases in prices of fossil-fueled generation, compared to what they would have been without the regulations (reflecting, in some modest part, internalization of costs these resources impose). The incremental cost impacts of complying with new, more stringent environmental regulations add to pressures on already increasingly uneconomic existing fossil fuel and nuclear resources.

From a price perspective, changing market conditions, including plentiful low-cost natural gas and increasing amounts of both zero-fuel cost renewable and customer-driven demand

[85] Order 2000, p. 152, http://www.ferc.gov/legal/maj-ord-reg/land-docs/RM99-2A.pdf

[86] See Tierney 2016, at p. 1. This recent report points to a series of market drivers that have been underway since at least 2000, which have contributed to the decline of the coal industry, including “declining coal-mining productivity, shifts in global demand for coal, the shale-gas revolution which eroded coal’s price advantage, the ever-increasing efficiency with which consumers use electricity, the overall flat demand in the power sector….”

side resources, are driving down energy prices. These declining energy prices leave less economic fossil fuel and nuclear generators that are failing to cover their costs in the energy market relying on capacity markets (in the places they exist) to assure their livelihoods or otherwise achieve higher margins. In some cases, market operators have responded to concerns that older coal and nuclear generation need assurances on the capacity market side by implementing rules favorable to these resources.[87] (Illinois and New York, too have addressed the issue with a direct subsidy approach, which has implications for wholesale capacity markets.)[88] These efforts have had and continue to risk counterproductive consequences in discriminating against more flexible but less consistently dispatchable resources like wind and solar power and some types of DERs. Market design reform should step back from the singular goal of protecting fossil and existing nuclear power plants to take advantage of all available resources and the goal of reliably and cost-effectively integrating a changing resource mix.

In some cases, market operators have responded to concerns that older coal and nuclear generation need assurances on the capacity market side by implementing rules favorable to these resources. (Illinois and New York, too have addressed the issue with a direct subsidy approach, which has implications for wholesale capacity markets.) These efforts have had and continue to risk counter-productive consequences in discriminating against more flexible but less consistently dispatchable resources like wind and solar power and some types of DERs. Market design reform should step back from the singular goal of protecting fossil and existing nuclear power plants to take advantage of all available resources and the goal of reliably and cost-effectively integrating a changing resource mix.

From an operations perspective, the retirement of fossil fuel units has proven eminently manageable across the country, and there is no reason (or study) to suggest that should change if retirements increase in scale going forward.[89] For example, studies in MISO, PJM and other market regions demonstrate that regional approaches to compliance with the U.S. EPA's Clean Power Plan are not only manageable from a reliability perspective but are the most cost-effective method to compliance.[90] (The regulations are at significant risk of repeal

87 See Chen 2015. https://www.nrdc.org/experts/jennifer-chen/auction-shows-mid-atlanticmidwest-consumers-will-pay-more-and-dirtier.

88 See e.g., Illinois S.B. 2814, The Future Energy Jobs Bill (providing Exelon $235 million in nuclear support) and New York Public Service Commission, Order Adopting a Clean Energy Standard, Cases 15-E-0302 and 16-E-0270 (Aug. 1, 2016) (directing $965 million to New York nuclear plants in first two years), http://on.ny.gov/2amOKZI.

89 See Moore, J. 10 Ways the Clean Power Plan Protects Electric Grid Reliability. 2015. https://www.nrdc.org/experts/john-moore/10-ways-clean-power-plan-protects-electric-grid-reliability.

90 See commentary of and citations to example studies at Yeh, S. *PJM: Regional Cooperation Leads to Lower Costs and Enhanced Reliability*. 2015. https://www.nrdc.org/experts/starla-yeh/pjm-regional-cooperation-leads-lower-costs-and-enhanced-reliability; Moore, J. *Reliability Prescription for States for Cutting Carbon Pollution: Plan Ahead, Plan Together*. 2016. https://www.nrdc.org/experts/john-moore/reliability-prescription-states-cutting-carbon-pollution-plan-ahead-plan-together.

under the new Administration, but the studies on compliance approaches remain illustrative.) Power plant retirements are part of the regular course of business for transmission and distribution system planners. System reliability impacts are typically local, and grid operators have many means to address these impacts.

First, dealing with power plant retirements is a matter of course for regional grid operators, which exist to operate the grid reliably in light of expected (e.g., unit retirement) and unexpected disruptions on the transmission system. Since 2009, for example, PJM has retired 24,881 MW of coal unit capacity.[91] In the same period, MISO retired 5,713 MW of coal generation.[92] All of these retirements were handled within existing regional processes without experiencing material reliability issues.

Second, grid operators have both market mechanisms and planning tools available to address planned retirements.[93] Capacity markets, while flawed in several respects, do provide signals to existing power plants as much as three years in advance about whether they will remain economic. In addition, all FERC-jurisdictional, transmission-owning utilities are required to engage in system planning processes that typically look 10 years into the future. Most regions require power plant owners to provide at least a year's notice about a planned retirement (and FERC should require those regions that do not require at least a year's notice to do so). Regional transmission operators are required to cost-effectively plan for unit retirements, a reality that brings with it the opportunity to utilize emerging technologies and non-wires alternatives that can often address system conditions and requirements more affordably than new steel in the ground.

Planners incorporate future unit retirements as they consider the need for infrastructure investments. Similarly, state-required resource planning processes — at the state or utility level — also contemplate planned retirements and replacement resource needs.

Third, to the extent that many impacts to transmission systems from fossil-fueled power plant retirements are local in nature, cost-effective solutions are available to avoid or delay the need for more expensive generation or transmission. Targeted deployment of DERs like distributed solar and demand response (sometimes known in this context as "non-wires alternatives" or "non-transmission alternatives") with shorter time horizons than might be required for the development and construction of significant generation or transmission

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[91] See PJM generator deactivation data sheet, filtered for 2009–2016 Actual Deactivation Data. http://www.pjm.com/~/media/planning/gen-retire/generator-deactivations-xls.ashx.
[92] See Zichella, C. *Regional Transmission Organizations: Lessons for the West*. https://www.nrdc.org/sites/default/files/regional-transmission-organizations-west-ib.pdf.
[93] See Tierney, S., E. Svenson, and B. Parsons. *Ensuring Electric Grid Reliability Under the Clean Power Plan: Addressing Key Themes from the FERC Technical Conferences.* 2015. http://www.westerngrid.net/wp-content/uploads/2015/04/Full-Report-Ensuring-Electric-Grid-Reliability-Under-the-Clean-Power-P....pdf.

infrastructure, and at much lower cost, can be utilized.[94] ConEdison has used a well-publicized non-wires alternative to avoid substation, switching and feeder upgrades on the distribution system at cost savings estimated to be close to $1 billion.[95] While some transmission system needs are sometimes larger than an amount non-wires alternatives can effectively address, in isolation, localized transmission system reliability issues remain good targets.

The transition of the nation's power generating fleet is already well underway, and grid operators are increasingly thinking about resource adequacy and reliability in terms of systems dominated by renewable energy and natural gas generation. In some instances, operators (and the resource adequacy and reliability standards to which they are obligated) are increasingly outdated in light of the transition. It is critical that FERC, as well as the North American Electric Reliability Corporation (the organization that develops grid reliability-related standards with FERC's oversight) and states, take on the issue of reforming reliability standards to represent our changing electric system.[96]

3. What are the market impacts of integrating increasingly higher levels of renewable resources with zero marginal cost?

The operational impacts of integrating increasingly higher levels of renewable resources are addressed, to some extent, in the answers to questions 2 and 4. Increasing penetrations of renewable energy have been managed without significant fanfare by existing RTOs and ISOs. As noted in a recent report, "[r]enewable energy has moved beyond what many once saw as an uneasy coexistence with coal, gas, and nuclear power to a more multifaceted and more thoroughly integrated role where these technologies provide essential reliability services similar to those from conventional thermal facilities."[97]

For example, technological advancements have improved near-term forecasting of wind and solar resources, and better aligned forecasting capability with dispatch and market

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[94] In addition to FERC's general admonition in Order No. 890 and Order No. 1000 that planners should give non-wires alternatives "comparable treatment" to transmission investment as potential solutions to grid needs, FERC has noted specific failures to do so. For example, in considering proposed revisions to MISO's tariff provisions regarding System Support Resources (SSRs) — those resources MISO has determined cannot retire because they are needed for reliability purposes for some period of time beyond the owners' planned retirement dates — FERC required MISO to make changes to ensure "thorough consideration of all types of SSR alternatives in an open and transparent manner," before awarding SSR status, including by allowing yet-to-be committed demand response and ensuring consideration includes other DERS as well. *Midwest Independent Transmission System Operator, Inc.*, Order Conditionally Accepting Tariff Revisions and Requiring Compliance Filings, 140 FERC ¶ 61,237 at ¶ 36 (2012).

[95] See recent reporting on the project at http://www.utilitydive.com/news/the-non-wire-alternative-coneds-brooklyn-queens-pilot-rejects-traditional/423525/.

[96] The Bipartisan Policy Center's report *Capitalizing on the Evolving Power Sector: Policies for a Modern and Reliable U.S. Electric Grid* (2013) at p. 60 suggests a cost-benefit framework by which to examine the cost-effectiveness of existing reliability standards, http://bipartisanpolicy.org/wp-content/uploads/sites/default/files/Energy_Grid_Report[1].pdf.

[97] Bradley, M. J. 2017. http://www.mjbradley.com/reports/powering-future-renewable-energy-grid-reliability.

structures. In a policy move recognizing this advancement, FERC's requirement that scheduling be available on at least a 15-minute basis aids in facilitating the variable nature of wind and solar, the forecasting for which is significantly more accurate 15 minutes in advance than an hour in advance.[98]

Technology and regulation have similarly meshed to change the requirements for wind and solar generators in relation to grid disturbances to improve the reliability of integrating high levels of renewable energy resources. Historically, the direct current-production nature of solar PV and the variable nature of both solar PV and wind could lead to challenges with grid integration. The inverters that converted their power production into the stable alternating current necessary to inject power into the grid generally were not capable of making the adjustments necessary to react to grid imbalances. As a result, both the technical standards for inverters, issued by the Institute of Electrical and Electronics Engineers (IEEE), and interconnection rules issued by states and FERC, required these inverters to trip off their generators in the event of a grid imbalance or disturbance.[99] As renewable energy penetration has increased (especially distributed systems), large amounts of generation going offline in the instance of a grid disturbance could have significant negative impact.

Inverter technology has improved such that these resources can stay online and not only avoid making problems worse but also contribute to restoring grid frequency. In light of these realities, both IEEE and FERC have changed their rules to allow for and require, respectively, renewable energy resources to have the capability to "ride through" grid disturbances by reacting to them in a way that avoids further damage or helps to resolve system stability.[100] In most cases it is the states, and not FERC, which determine interconnection procedures for smaller generating resources. Some states have made progress to move forward with advanced inverter deployment, and others still have room for policy improvement.

Additionally, the technological and regulatory ability of DERs to support the integration of renewable energy cost-effectively has increased significantly over the last several years. Software and hardware are now widely available to support the ability of end-use customers to decrease or increase their electricity use upon request, often via aggregators in response to grid operator instructions. FERC responded to this reality in its issuance of Order No. 745, which requires wholesale energy markets to provide for demand response participation and

[98] Order 764. Integration of Variable Energy Resources. 139 FERC ¶ 61,246 (2012). https://www.ferc.gov/whats-new/comm-meet/2012/062112/E-3.pdf.
[99] See IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems. http://grouper.ieee.org/groups/scc21/1547/1547_index.html.
[100] See Final Rule, Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities. 156 FERC ¶ 61,062 (2016). https://www.ferc.gov/whats-new/comm-meet/2016/072116/E-11.pdf; see also related Final Rule, Reactive Power Requirements for Non-Synchronous Generation. 155 FERC ¶ 61,277 (2016). https://www.ferc.gov/whats-new/comm-meet/2016/061616/E-1.pdf.

to be compensated at full locational marginal pricing when clearing the market and providing net benefits to the system.[101] This technological and regulatory combination allows for demand response resources to support short-term variations in supply and demand in light of the variable nature of wind and solar resources (although again, it is important to avoid overstating the challenges grid operators face in integrating these resources).

On the pricing side, zero-marginal cost renewable energy drives down energy prices in wholesale markets, even as far as creating negative pricing situations. In these situations, wind generators (which also receive payments related to their renewable energy attributes and qualify for production tax credits based on the amount of power produced regardless of the rate at which they sell) pay to produce energy, often at night when the wind is blowing and electricity demand is low.[102] Instances of negative pricing represent the need for reform to ensure that the whole suite of wholesale markets — capacity and ancillary service markets included — are properly valuing the set of services that the grid needs to ensure reliability and resource adequacy with an evolving resource mix.[103] These instances are likely to increase, so now is the time to proactively address issues around the correct market design and products.

Declining energy prices means that increasingly uneconomic fossil fuel and nuclear resources are looking to the capacity markets to recover costs. As a result, regional grid operators and states focused on maintaining system reliability are looking for ways to enhance capacity payments to the level necessary to maintain existing resources and incent new resource development. As mentioned above, PJM has changed its capacity market rules to lock in payments to baseload and fully dispatchable peaking power plants that can run every day, all year. While the need to maintain reliability is obviously paramount, two concerns emerge from the approach of doubling down on capacity markets. First, in light of a rapidly evolving resource mix, reliability standards are outdated and the approach to day-to-day operational reliability has and will continue to change. Second, blunt capacity products limit the types of resources that can

[B]lunt capacity products limit the types of resources that can provide capacity services — perhaps excluding cost-effective demand response, targeted energy efficiency and other aggregated DERs — leading to ... over-procurement and higher cost....

[101] Order 745. Demand Response Compensation in Organized Wholesale Energy Markets. 18 CFR Part 35 (2011). https://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf; *FERC v. Electric Power Supply Association*. 136 S.Ct. 760 (2016). https://www.supremecourt.gov/opinions/15pdf/14-840_diff_pok0.pdf.
[102] See, e.g., this U.S. Energy Information Administration brief on negative pricing issues in Texas. http://www.eia.gov/todayinenergy/detail.php?id=16831.
[103] See, e.g., Bloomberg. One Thing California, Texas Have in Common Is Negative Power. April 5, 2016. https://www.bloomberg.com/news/articles/2016-04-05/one-thing-california-texas-have-in-common-is-negative-power.

provide capacity services — perhaps excluding cost-effective demand response, targeted energy efficiency and other aggregated DERs — leading to the over-procurement and higher cost issues considered above.

A better approach may be to think through the type of capacity that the grid will need going forward and to invoke reform based on those needs. For example, perhaps a seasonal capacity product or a monthly capacity construct (as is used in California),[104] or even a capacity product that clears more often than hourly, is an effective way to ensure the flexible capacity that the grid needs will be available in the future. It is not clear that capacity markets as they currently exist are the right mechanism to take the electricity system cost-effectively into the future.[105] One promising conceptual example for considering market reform comes from the Regulatory Assistance Project in its discussion of "capabilities markets."[106] Capabilities markets consider net demand after the deployment of available renewable energy resources and focus on the capabilities necessary to cost-effectively and reliably facilitate those resources' production.

More generally, all resources that are providing services the electric grid needs to facilitate reliable electricity delivery in an era of increasing renewable energy resources should be compensated for their contributions.

For example, energy storage has the ability to contribute to managing the changing operational and pricing aspects of high renewable energy integration. States, regions and the federal government have worked to encourage storage commercialization. California enacted an energy storage procurement target of 1,325 megawatts by 2020.[107] PJM has at least 270 MW of storage in service and over 1,800 MW in some stage of its interconnection queue.[108] FERC has worked to facilitate the role of storage as both an operational asset eligible for utility cost recovery and, more recently, as an important market participant.[109] As noted below, however, while we continue to work towards decreasing storage prices,

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104 See California ISO. Reliability Requirements. http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx.

105 An interesting discussion of this issue is found at Hogan, M. *Energy Prices, Not Capacity Mechanisms, are Key to Ensuring Reliability at the Lowest Cost.* Regulatory Assistance Project. 2016. http://www.raponline.org/energy-prices-not-capacity-mechanisms-key-ensuring-reliability/?_sf_s=capacity+markets.

106 See Regulatory Assistance Project. *What Lies Beyond Capacity Markets?* 2012. http://www.raponline.org/wp-content/uploads/2016/05/rap-hogan-whatliesbeyondcapacitymarkets-2012-aug-14.pdf.

107 See California Energy Commission. Energy Storage Showcase. http://www.energy.ca.gov/research/energystorage/tour/.

108 See PJM Interconnection Status page: http://www.pjm.com/planning/generation-interconnection/generation-queue-active.aspx.

109 See Western Grid Development, LLC. 130 FERC ¶ 61,056 (2010). https://www.ferc.gov/whats-new/comm-meet/2010/012110/E-6.pdf; and Notice of Proposed Rulemaking. *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators.* 157 FERC ¶ 61,121 (2016). https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-1.pdf.

expanding the interconnectedness of grid systems can go a long way towards managing both operational and pricing impacts of our changing resource mix.

4. Are today's market designs adequate to acquire the flexible resources needed to better integrate increasing levels of variable energy resources at least cost?

Achieving higher renewable energy penetrations at consistent levels at least cost, however, will require some evolution beyond existing capacity and ancillary service markets to a more dynamic set of grid services. Some regions have already taken steps towards providing some sort of flexibility service.

Existing wholesale markets have had success in integrating high penetrations of renewable energy. For example, renewable energy represented 56 percent (15,843 MW) of the power on CAISO's system at a high in 2016 and 52.1 percent of all power on SPP's system in February 2017,[110] without technical difficulty. Renewable energy grid integration studies demonstrate that both the Western and Eastern Interconnections can effectively manage penetrations of renewable energy as high as 30 percent to 60 percent or more without the development of new grid services.[111]

Achieving higher renewable energy penetrations at consistent levels at least cost, however, will require some evolution beyond existing capacity and ancillary service markets to a more dynamic set of grid services. Some regions have already taken steps towards providing some sort of flexibility service. Many of the changes may be region-specific — for example, what works in the Intermountain West may not be suitable for New England. In light of significant penetrations of wind and solar power, MISO and CAISO have led the way in developing market-based products that provide a flexibility service necessary to complement wind and solar power's variable characteristics. MISO's "ramp capability product" is a non-bid based service provided through optimizing day-ahead and real-time bids to cover "a short-term scarcity event because MISO has inadequate ramp capability to respond to unexpected variations" in load.[112] CAISO created a flexible ramping product and flexible capacity

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110 CAISO. Solar Power Production Sets New Record in California. 2016. http://calenergycommission.blogspot.com/2016/07/solar-power-production-sets-new-record.html; and SPP. SPP sets North American record for wind power. 2017. https://spp.org/about-us/newsroom/spp-sets-north-american-record-for-wind-power/.

111 See, e.g., National Renewable Energy Laboratory, *Western Wind and Solar Integration Study* (Phases I and II), http://www.nrel.gov/grid/wwsis.html; GE Energy et al. *PJM Renewable Integration Study*. 2014. http://www.pjm.com/committees-and-groups/subcommittees/irs/pris.aspx; Southwest Power Pool Operations and Planning Engineering. *2016 Wind Integration Study.* https://www.spp.org/documents/34200/2016%20wind%20integration%20study%20(wis)%20final.pdf.

112 FERC. Order Conditionally Accepting Tariff Revisions. 149 FERC ¶ 61,095. https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Orders/2014-10-31%20149%20FERC%2061,095%20Docket%20No.%20ER14-2156-000.pdf.

requirements intended to address increased ramping needs due to higher penetrations of renewable energy on its system.[113] CAISO's DER aggregation rules, described in response to Question 1 above, goes a step further in providing a platform for the flexibility necessary to incorporate high levels of renewable energy.

MISO and CAISO's approaches are good models to support increasing penetrations of renewable energy on their systems. FERC has the authority to consider the existing suite of required ancillary services, which in their current form date back to 1996, to consider whether a changed electric grid merits comprehensive or incremental reform. While new ancillary services will be necessary, it is important not to overstate concerns related to a grid powered predominately by variable resources.

Regionally interconnected grids alone can manage high penetrations of renewable energy without the development of new services. In the West, the recently developed energy imbalance market, a wholesale market facilitated by CAISO that allows for real-time reserve sharing between Western U.S. balancing authorities (mainly utilities), demonstrates this potential[114] (see Figure 3.3.). Since its inception in 2014, the market has provided $142.62 million in benefits to participating utilities (and their customers).[115] It allows for efficiencies in that each utility will not have to maintain its own full suite of reserves. The market can also facilitate integration of higher penetrations of renewable energy resources by balancing out unexpected imbalances between electricity supply and demand.

CAISO, utilities in the West and interested states are also considering development of a full multi-state RTO that would go well beyond the ability of an energy imbalance market in achieving cost efficiencies and renewable resource integration. Other Western U.S. utilities are considering joining SPP or another regional grid organization.[116] Although regulatory and institutional barriers to development of a multi-state RTO exist, the potential cost-saving and environmental benefits have brought together a diverse set of stakeholders to consider future options. "Failure to regionalize grid operations to incorporate a broader western footprint likely will cost consumers billions of dollars over time, require the development of duplicative infrastructure and generation because less resource sharing will be possible, and

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[113] See FERC. Order on Tariff Revisions. 156 FERC ¶ 61,226. https://www.caiso.com/Documents/Sep26_2016_OrderAcceptingFlexibleRampingProductTariffAmendment_ER16-2023.pdf.

[114] See CAISO. Western Energy Imbalance Market (EIM). 2017. https://www.caiso.com/informed/Pages/EIMOverview/Default.aspx. Currently participating or committed members include PacifiCorp, NV Energy, Puget Sound Energy, Arizona Public Service, Portland General Electric and Idaho Power. Other investor-owned and publicly owned utilities have expressed their interest in studying participation.

[115] See CAISO. Western EIM Benefits Report Fourth Quarter 2016 (Jan. 30, 2017). http://www.caiso.com/Documents/ISO-EIMBenefitsReportQ4_2016.pdf.

[116] See Mountain West utilities may join an RTO; Southwest Power Pool is the first try. 2017. https://www.hubs.com/power/explore/2017/01/mountain-west-utilities-may-join-an-rto-southwest-power-pool-is-the-first-try.

make regulatory compliance more difficult and expensive for states in the Western Interconnection region."[117]

The technology necessary to sustain a majority-renewables power grid cost-effectively and reliably exists today. Removal of market participation and other regulatory and institutional barriers will allow that technology to support the grid evolution that is already underway.

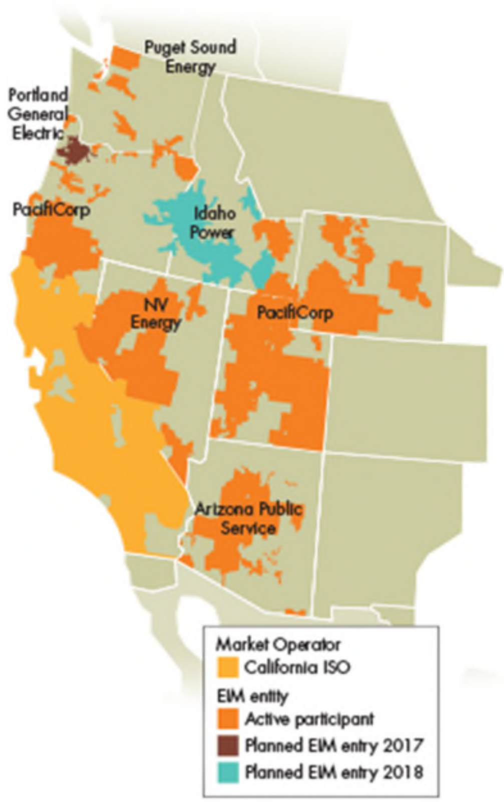

Figure 3.3. Western U.S. Energy Imbalance Market.[118]
This map of the current members of the Western U.S. Energy Imbalance Market shows initial signs of coordination to decrease the balkanization of the West's 38 separate balancing authorities.

Conclusion

Existing wholesale markets are not designed to facilitate public policies. FERC, RTOs and ISOs, and involved stakeholders must achieve reform so that wholesale competition and state and federal public policy can coexist. The failure to achieve this market reform risks costing customers money, impugning reliability, and imperiling the success of state and federal environmental policies. Although the issues through which reform must navigate are complex, significant opportunity exists.

[117] Natural Resources Defense Council. *Making Sense of a Potential Western ISO: The Role of FERC in Transmission Service*. 2016. https://www.nrdc.org/resources/regional-transmission-organizations-recommendations-west.
[118] CAISO 2017. https://www.caiso.com/informed/Pages/EIMOverview/Default.aspx.

4. A Consumer Advocate's Perspective on Accommodating State Goals and Diverse Resources in Centrally-Organized Wholesale Electricity Markets

By the National Association of State Utility Consumer Advocates[119]

Introduction

More than two-thirds of U.S. electricity consumers live in regions participating in centrally-organized wholesale electricity markets. Yet there is still a significant portion of the country where the electric grid is managed by individual utilities or utility holding companies without a regional market.

NASUCA's members represent consumers in individual states, not according to RTO/ISO market regions. [120] Many state members participate in more than one market region. This section of the report presents a general consumer perspective and does not necessarily reflect the views of any particular state or NASUCA as a whole.[121] While the discussion that follows is focused on current issues in regions with centrally-organized wholesale markets, some issues overlap with non-market regions due to both national and individual state policies.

Consumers benefit when the costs of electricity consumption are as low as possible over the long term, consistent with reliable service, environmental standards, and policy goals required

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[119] NASUCA's comments were developed by a subcommittee of interested NASUCA members and approved by the NASUCA Executive Committee. Robert Mork, chair of the NASUCA Electric Committee, led the subcommittee's work. Paul Peterson and Sarah Jackson, Synapse Energy Economics, Inc., provided technical assistance.

[120] NASUCA is a nonprofit voluntary association of advocate offices in more than 40 states and the District of Columbia. NASUCA members are designated by the laws of their respective jurisdictions to represent the interests of utility consumers before state and federal regulators and in the courts. Members operate independently from state utility commissions as advocates primarily for residential ratepayers. Some members represent only residential consumers; some members represent residential and small business consumers; and other members represent all utility consumers in their states. Some NASUCA member offices are separately established advocate organizations, while others are divisions of larger state agencies (e.g., the state Attorney General's office). NASUCA's associate and affiliate members also serve utility consumers but are not created by state law or do not have statewide authority. Each individual NASUCA member reserves the right to take positions or advance views that are consistent or inconsistent with this document.

[121] NASUCA is a nonprofit voluntary association of advocate offices in more than 40 states and the District of Columbia. NASUCA members are designated by the laws of their respective jurisdictions to represent the interests of utility consumers before state and federal regulators and in the courts. Members operate independently from state utility commissions as advocates primarily for residential ratepayers. Some members represent only residential consumers; some members represent residential and small business consumers; and other members represent all utility consumers in their states. Some NASUCA member offices are separately established advocate organizations, while others are divisions of larger state agencies (e.g., the state Attorney General's office). NASUCA's associate and affiliate members also serve utility consumers but are not created by state law or do not have statewide authority. Each individual NASUCA member reserves the right to take positions or advance views that are consistent or inconsistent with this document.

by federal and state governments. This is a bedrock principle for NASUCA members and is the starting point for our analysis and comments in this report.

Ultimately, consumers pay for all the reasonable costs of the electric system, both wholesale and retail. Over the last hundred years, states have developed mechanisms and institutions to ensure that consumers of electricity have a voice in state processes for reviewing and approving the costs of regulated utilities for providing electricity. In most states, separate consumer advocate offices have been established by legislation to augment other protection mechanisms embodied in utility regulation laws.

This section of the report provides NASUCA's response to specific questions about whether markets can adequately address new technology attributes and whether markets can adequately allocate the costs and benefits of state policy requirements. As such, NASUCA addresses only a small portion of the myriad of factors that come into play when we seek to ensure safe, reliable and reasonably priced service. While those additional factors are outside the narrow scope of the questions presented in this report, NASUCA must emphasize the importance of state policy and state regulation in providing the ultimate protection for customers.

Before responding individually to each of the four questions this report addresses about wholesale markets, we highlight a few issues that apply generally.

Ensuring Robust Participation by Consumer Advocates in RTO/ISO Processes

RTOs/ISOs are a relatively new expansion of utility regulation, and a significant portion of consumers' retail electricity bills comes directly from federally regulated RTO/ISO charges. NASUCA members' ability to effectively represent consumer interests is limited by the challenge of participating on an even footing with other industry participants in these regional and federal forums.

The RTO/ISO governance structures required and approved by FERC include a prominent role for a stakeholder process to identify issues and develop solutions. While these processes vary considerably from one RTO/ISO to another, they are all crafted to enable some degree of participation from a broad range of stakeholders across the electric utility industry. Consumers need and generally have an opportunity to be heard in these stakeholder meetings. However, consumer representatives also need meaningful opportunities to offer feedback and assurance that such feedback will be taken seriously. The importance of being in the room when important decisions are being made cannot be overstated.

In addition to a seat at the table, consumers need adequate resources to be able to effectively participate in the myriad committees, subcommittees and working groups that RTOs/ISOs create. These stakeholder groups develop tariffs, rules and mechanisms to enable the RTO/ISO to operate its markets, identify necessary infrastructure investments, and manage the grid.

State consumer advocate offices were not designed or budgeted with a view toward addressing the many and varied issues which are now part of the federally approved RTO/ISO constructs. Too often, the time and expense required for all of these stakeholder activities make it challenging for NASUCA members to fully participate in developing the market designs and planning structures that can have substantial impacts on consumers' monthly costs. RTOs/ISOs can better enable participation by resource-constrained stakeholders by ensuring that such activities are noticed well in advance, that detailed supporting materials are made available in advance, that NASUCA members have sufficient resources to perform meaningful evaluation, and that there is sufficient opportunity for stakeholder feedback.

Public service commission participation in RTOs/ISOs has long been subsidized as a routine part of RTO/ISO governance structures. Resource-constrained state consumer advocates should be treated similarly. In the PJM region, a group known as the Consumer Advocates of the PJM States (CAPS) was established in 2013 to provide a consistent presence for state consumer advocates in the PJM stakeholder process. This group began with funding through state settlement funds from a FERC enforcement action. In 2016, PJM stakeholders approved ongoing funding for CAPS through the PJM tariff, which FERC then approved. Although CAPS members retain their individual PJM membership and involvement in the stakeholder process, they now have the assistance of a CAPS executive director who provides expert analysis, helps cover meetings that individual offices may not be able to attend, and reports to a board comprised of all the individual state consumer advocates in the PJM region. The approach has enabled state consumer advocates to be far better informed on PJM issues and enabled them to engage earlier and more constructively in addressing PJM stakeholder issues, to the benefit of both consumers and other stakeholders. This approach may be a model for other RTO/ISO regions.

> ***RTOs/ISOs can better enable participation by resource-constrained stakeholders by ensuring that such activities are noticed well in advance, that detailed supporting materials are made available in advance, that NASUCA members have sufficient resources to perform meaningful evaluation, and that there is sufficient opportunity for stakeholder feedback.***

Another way in which RTOs/ISOs can support effective participation of consumers and their representatives is by providing independent cost and benefit analyses for major initiatives. These analyses should be done in conjunction with distribution utilities and should include estimates of impacts on both wholesale and retail energy costs. Before approving major changes to tariffs or market rules, FERC should require the filing and consideration of these studies. In New England, for instance, the ISO produces an estimate of economic impacts for any "major" rule changes and provides its analysis to stakeholders.[122]

[122] ISO New England (ISO-NE) limits its analysis to impacts on wholesale rates, not retail rates, as defined by its tariff. In response to FERC Order No. 719, ISO-NE amended the mission statement in its tariff to include the following: *To assist stakeholders in evaluating any major ISO initiative that affects market design, system planning, or operation of*

Preserving State Jurisdiction

Historically, states have had jurisdiction over the types of resources needed to address electrical demand from residential consumers and commercial and industrial users. Today, many states have implemented policies that require adoption of demand management programs, procurement of renewable resources, reduction of greenhouse gases, and purchase of specific technology types such as solar photovoltaic (PV) systems, offshore wind, hydro and nuclear power through special credits, contracts or other forms of financial support.[123] These policies can impact prices in wholesale electricity markets, which are designed by RTOs/ISOs to be resource-neutral, similar to traditional commodity markets.

For example, a particular state may decide as a matter of public policy to require its utilities to purchase a certain amount of renewable energy from qualified resources, such as wind. Although wind plants are often more expensive to build than other generating resources on a capital cost basis, wind is a renewable resource with essentially a zero fuel cost. The compensation of wind resources by markets differs significantly from that of fossil fuel resources due to their different performance characteristics, and major wind developments in turn impact the clearing prices in regional electricity markets. Due to the variability of wind resources, the capacity value of wind (i.e., the value wind provides toward meeting reliability requirements) is less on a per megawatt basis than that of a fossil-fuel resource with an on-demand fuel supply. That leads to lower capacity market compensation for wind in regions that have developed capacity markets. On the energy market side, the lack of fuel costs enables wind resources to participate in the market at very low or even negative marginal energy prices.

Another way that states encourage renewable resources such as wind in regions with wholesale electricity markets is to monetize the renewable attributes sought by state renewable portfolio standards (RPS) in the form of "renewable energy credits" (RECs). An REC is an additional source of revenue for a renewable resource that can be tracked and traded separately. This payment is in addition to revenue from the wholesale energy markets. This helps offset some of the higher capital costs of these resources. Utilities and alternative electricity suppliers that are required to meet RPS requirements buy the needed RECs (either by contracting directly or through a third-party broker) to demonstrate RPS compliance.

Some RTOs/ISOs use minimum offer price rules to exclude resources from participation in capacity markets because they receive payments through such a contract, direct subsidy, or other non-market revenue source. In these situations, unless those excluded resources are

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the New England bulk power system, the ISO will provide quantitative and qualitative information on the need for and the impacts, including costs, of the initiative. See https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_1/sect_i.pdf.

123 Examples of these policies include energy efficiency resource standards and demand response initiatives, renewable portfolio standards that require a percentage of delivered energy to come from qualified renewable resources, the Regional Greenhouse Gas Initiative in the Northeast U.S. that caps carbon dioxide (CO_2) emissions for the electric sector, the Massachusetts Global Warming Solutions Act requiring specific reductions in CO_2 emissions over time, New York's Clean Energy Standard which includes credits for nuclear power, and numerous state-specific solar and wind incentives in support of these resources.

appropriately factored into the RTO's/ISO's calculation of its capacity needs, consumers are at risk of paying for additional, unnecessary capacity resources. Consumers would be better served by market rules that ensure that where state policies create contractual obligations for consumers, RTOs/ISOs will recognize the contribution that these contracted resources provide to system capacity needs, other system needs, and overall resource adequacy in the region. At the same time, RTO/ISO market structures and design should avoid imposing any inappropriate costs of one state's policies on consumers in other states, and should ensure just and reasonable compensation for all energy resources.

…RTO/ISO market structures and design should avoid imposing any inappropriate costs of one state's policies on consumers in other states.…

A recent Supreme Court decision in *Hughes v. Talen* concluded that a particular contract-for-differences approach to power plant development constituted impermissible interference with FERC jurisdictional markets. In that decision, the Court suggested that numerous other mechanisms to implement state resource policies could be designed to avoid such a direct intervention. However, as of this writing it is not clear what specific state actions (that are not an exact repeat of the rejected contract-for-differences approach) will be considered permissible.[124]

Overall, in order for centrally organized markets to function in concert with state policy requirements, RTOs/ISOs must explore ways to accommodate state-preferred resources in RTO/ISO markets and reflect the appropriate value that each particular resource provides.

Following are NASUCA's responses to the four questions this report addresses.

1. **Are today's centrally-organized market designs adequate to accommodate state public policy goals, and what potential design changes would further enable deployment of resources that achieve the goals of reliability, affordability and preferred resource mix?**

NASUCA's general response to the first part of this question is no, the current centrally-organized market designs are experiencing great difficulty integrating state policy goals and the new resources that those policies support. Every state in the three Northeast RTO/ISO regions has significant concerns regarding how resources supported by state policy will participate in the centrally organized markets and how the costs and benefits of these resources will be shared.

Overall, in order for centrally-organized markets to function in concert with state policy requirements, RTOs/ISOs must explore ways to accommodate state-preferred resources in RTO/ISO markets and reflect the appropriate value that each particular resource provides.

[124] *Hughes v. Talen Energy Marketing*. No. 14-614. April 19, 2016. https://www.supremecourt.gov/opinions/15pdf/14-614_k5fm.pdf.

Many of these concerns are also shared by NASUCA members whose states do not participate in centrally organized markets.

The wholesale power markets were originally designed with traditional, central-station, dispatchable fossil- and nuclear-powered resources in mind. As such, these market designs have struggled to adapt to a system increasingly powered by the renewable energy technologies and demand-side management tools being promoted through state and federal policies such as RPS and energy efficiency resource standards.

Existing state public policies have already impacted wholesale electricity market designs, as well as traditional assumptions about loads and generation. These impacts can be seen in forecasts that show declines in annual energy consumption and load growth, as more behind-the-meter resources such as energy efficiency, load controls, rooftop solar, and combined heat and power displace traditional grid-supplied energy.

NASUCA members are advocates for consumers in their states. They are not necessarily responsible for establishing state policies that encourage development of energy efficiency, demand response and renewable resources, but they are concerned about whether such policies are providing benefits to consumers. Consumer advocates want the resources incentivized under these policies to be properly valued in centrally-organized electricity markets. Overstating or understating their value, or excluding them from participation in those markets, will likely result in consumers paying higher costs than necessary.

Some regions have adopted new market rules that define resource performance in ways that exclude certain resources from participation. In New England and PJM, for example, market operators recently adopted "pay for performance" rules that will penalize any resource that is not available in any hour that it is needed. The intent is to ensure that resources that are paid through the capacity market are actually available when called upon. This need was formerly determined by the ability to deliver power during peak time, generally during the hottest summer days. With the new pay for performance rules, resources must be able to respond and be available at any time in which a so-called shortage event may occur or they will be assessed a penalty. These shortage events can occur at any time for any number of reasons (including tripped generators or downed transmission lines) and are much more difficult to predict than peak load periods.

The challenge is to create market designs that can properly monetize the value of resources supported by state policies, ensure the resources are paid for their actual value given their performance and characteristics, and accommodate their participation in centrally organized markets by properly assigning the costs and the benefits to consumers. That will allow the competitive markets to select the most cost-effective mix of resources.

The challenge is to create market designs that can properly monetize the value of resources supported by state policies, ensure the resources are paid for their actual value given their performance and characteristics, and accommodate their participation in centrally organized markets by properly assigning the costs and the benefits to consumers. That will allow the competitive markets to select the most cost-effective mix of resources.

NASUCA's members have a range of opinions on the need for and usefulness of capacity markets. On the specific design issue of how long the commitment period should be in regions where capacity markets exist, NASUCA members do not support a single specific term. The current approach in New England and PJM is for one-year commitments for existing resources and multi-year commitments for all new resources (New England) or some new resources (PJM). Providing all resources with multi-year commitments puts consumers at greater risk for investments in resources that become uneconomic over time. Maintaining the existing one-year commitment rule protects consumers, but may result in higher annual offers from resources because they may include a risk premium in their offer to reflect the lack of a multi-year commitment. Limiting multi-year commitments to just new resources may be a reasonable approach.

RTOs/ISOs should develop markets that allow resources with different operating profiles to receive appropriate credit not just for energy and capacity, but also for the reliability and ancillary services needs that they can satisfy, and to be appropriately charged for any extraordinary costs they impose. Excluding resources, as well as trying to differentiate between the many different forms of subsidies among resources, could lead to consumers overpaying for capacity, reserves and other ancillary services. Current designs in centrally organized markets co-optimize energy and reserve needs to select the most cost-effective mix of resources on a daily basis. Expanding the market designs to co-optimize for other ancillary service needs in addition to energy and reserves is one option. If markets are to accommodate the significant growth in variable energy resources supported by state policies, markets must improve valuation of the costs and benefits of all resources so that the least-cost resource mix can be selected.

ANCILLARY SERVICES

In these comments, we divide electricity services into three categories: energy, capacity and ancillary services. Ancillary services are a broad category of services represented in Figure 4.1 that allow system operators to deliver electricity while ensuring system reliability and an appropriate balance between supply and demand.

These services are called by different names in different regions. They usually include contingency reserves, distinguished by 10-minute spinning reserves, 10-minute non-spinning reserves, and 30-minute operating reserves. The time values indicate how long before the resource can be synchronized and providing help to the system. Some regions such as ERCOT have special reserves that are available in seconds, not minutes. Other ancillary services include ramping, stability, regulation, automatic generation control, voltage control, and volt-ampere reactive services. Some services are compensated through competitive markets and others are compensated based on rate schedules.

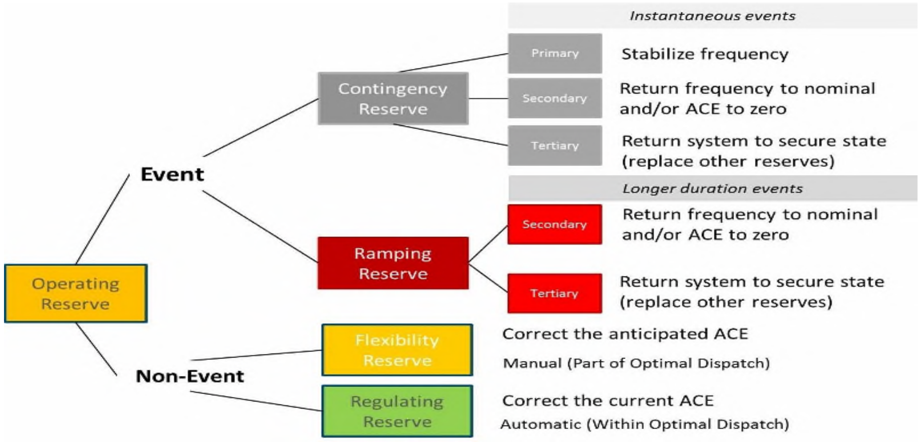

Figure 4.1. Ancillary Services for Electric Grids.[125]

Additional efforts to control electricity sector carbon emissions and promote clean resources may come through policies adopted by individual states, groups of states, or national standards, building on existing efforts:

- California has a loading order for the development of new resources that gives first preference to resources that reduce electricity consumption (energy

[125] "ACE" is Area Control Error. EPRI presentation, Oct. 19, 2016, slide 11, https://www.iso-ne.com/static-assets/documents/2016/10/a3_integration_and_planning_of_large_amounts_of_inverter_based_resources.pptx.

efficiency and demand response, including combined heat and power), second preference to zero-carbon emitting resources (wind, solar, batteries), and third preference to low-carbon emitting resources (natural gas).
- New York is restructuring its electricity distribution system to better align state policy goals, the operation of the distribution utilities, and interactions between the distribution utilities and the NYISO markets.
- Massachusetts recently enacted legislation that will require distribution utilities to include specific quantities of offshore wind resources and hydro imports to meet state carbon reduction laws.
- Dozens of states have adopted Renewable Portfolio Standard and Energy Efficiency Resource Standard requirements.
- The Regional Greenhouse Gas Initiative, a cooperative effort of nine Northeast states to address carbon emissions through a regional cap on carbon-emitting resources in the electric sector, is evaluating whether to strengthen its program by reducing its cap.
- The Western Climate Initiative works to facilitate a voluntary cap-and-trade program among California and three Canadian provinces.
- On a national level, the U.S. Environmental Protection Agency (EPA) proposed the Clean Power Plan (CPP), which is designed to provide several pathways to reduce each state's carbon footprint through a combination of operational changes at fossil resources, shifting of generation from high-emitting coal and oil plants to lower-emitting natural gas plants, and the development of zero-emitting renewable resources.[126]

The challenge for operators of wholesale markets is to develop mechanisms that can properly monetize those state goals and state preferences so that states may pay for their preferred resources, while minimizing the imposition of costs on other states.

Consumer advocates want to ensure that the costs of state and federal policies are properly evaluated through transparent analyses that demonstrate both the short-term and long-term benefits and costs to electricity consumers. States have diverse interests, and each state may adopt specific policy goals to promote new technologies or broad goals to achieve renewable portfolio standards or greenhouse gas reductions. There may be common themes among states and conversely, there may be states that do not support other states' goals. The challenge for operators of wholesale markets is to develop mechanisms that can properly monetize those state goals and state preferences so that states may pay for their preferred resources, while minimizing the imposition of costs on other states.

[126] The Clean Power Plan is the subject of judicial review, and its future uncertain as a result of the recent election.

> ***States that have restructured and whose electricity needs are served by centrally organized markets need to have RTO/ ISO market designs that both support their state policies and properly allocate the costs of those policies. NASUCA members continue to support state discretion and do not support a shift of resource selection or resource adequacy responsibility to either RTOs/ISOs or FERC.***

Separating costs in centrally organized markets can be difficult. Many market mechanisms are explicitly designed to share costs widely. For example, current market designs allocate daily reserve costs to be paid for by all consumers, even though it is specific large resources that require increased reserve margins in case they experience an unexpected outage or contingency. When a large generator retires, leaving a hole in the transmission system, current rules socialize the costs of the necessary system upgrades to a specific load zone rather than charging those costs to the retiring generator. Similarly, when a contingency occurs and energy prices increase over the short-term (until additional resources can be brought onto the system) or long-term (when those additional resources cost more), centrally organized markets do not allocate those higher energy prices to the resource(s) that caused them. Instead, all consumers in a load zone, sometimes several load zones, pay the higher energy prices. On the other hand, when a new resource interconnects to the system and that interconnection causes adverse impacts, that resource must pay for the upgrades needed to resolve those issues.

Many studies have noted that variable renewable energy resources (wind and solar) will require additional ramping and regulation resources as they reach high penetration levels. The appropriate cost allocation for needed ramping and regulation services should be harmonized between the specific costs that such variable energy resources may impose in some hours, versus the general costs that the electric system experiences for ramping and regulation services on a daily basis.

Overall, consumer advocates want to preserve state authority and discretion to adopt and promote state policies. States that have not restructured (including those which operate in centrally organized markets) can do this through their existing authority to regulate vertically integrated utilities. States that have restructured and whose electricity needs are served by centrally organized markets need to have RTO/ISO market designs that both support their state policies and properly allocate the costs of those policies. NASUCA members continue to support state discretion and do not support a shift of resource selection or resource adequacy responsibility to either RTOs/ISOs or FERC.[127]

[127] See NASUCA Resolution 2014-04 that states:

NOW, THEREFORE, BE IT RESOLVED THAT NASUCA continues to support State authority: to preside over the procurement decisions of electric utilities; to decide the type, amount and timing of new generation facilities that will be constructed within the State to achieve legitimate State policy objectives; to promote new development of electric resources, including demand resources, through State supervision of retail utilities and utility procurement;

2. What are the market impacts of environmental regulations further constraining the deployment of fossil fuel resources?

NASUCA's general response is that environmental regulations have not impaired the reliable operation of the electric grid, with localized exceptions. The market impacts from the retrofitting and retirement of fossil fuel resources have been substantially mitigated by increased supplies of low-cost natural gas.

Environmental laws and regulations adopted over the last 40 years to protect the health of Americans have had significant impacts on traditional pollution-causing generating resources and will continue to influence future decisions by resource owners as to whether to invest in pollution control technology for the generating facility or retire it. The Quadrennial Energy Review describes laws and regulations that have had or are likely to have a significant impact on fossil fuel-fired generators.[128]

Many of these regulations require the installation of expensive control technologies to reduce the damaging effects of pollution. These controls add a new capital cost that must be recovered from energy sales that may make the plants more expensive to run compared to new and cleaner sources of electricity.

In conjunction with record-low natural gas prices, the resulting market impacts of these increasingly stringent environmental regulations include a significant shift towards new, gas-fired resources to replace the energy output of coal units in many parts of the country. New natural gas technologies are available at approximately the same total cost as new coal facilities.

There have been a small number of local reliability concerns associated with retiring coal resources, but overall the transition has been proceeding smoothly without interruptions to service. RTOs/ISOs are accustomed to working with large, central-station natural gas power plants that provide similar, if not better, operational characteristics than the coal plants in terms of availability, ramping capability, spinning reserves and other system benefits. One drawback is that, unlike coal and oil resources whose fuel can be stored on-site, gas units face some degree of uncertainty regarding gas supply and the fluctuating prices of that supply in both the near term and the long term. This has led to policies like the pay-for-performance rules described above and efforts to better coordinate the gas and electric

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to operate programs to procure new generation for reliability, affordability and environmental purposes through use of long-term contracts or any State statutory or regulatory actions; and to support efforts to ensure that nothing in the Federal Power Act be deemed to preempt or prohibit such activity by the States. http://nasuca.org/nasuca-electricity-resolution-2014-04/.

[128] U.S. Department of Energy. Quadrennial Energy Review - Transforming the Nation's Electricity System: The Second Installment of the QER. January 2017. Appendix: Electricity System Overview. pp. A-18 to A-22. https://www.energy.gov/sites/prod/files/2017/01/f34/Appendix%20_0.pdf.

markets. It has also increased the incentive to invest in on-site storage of a short duration supply of alternative fuels for gas generation plants.

The EPA's CPP has been evaluated in numerous studies. While its future is uncertain as a result of judicial review and the recent presidential election, the studies provide useful information about expected impacts of certain levels of resource transitions over defined time periods. Overall, such greenhouse gas (GHG) regulations are expected to support the shift from coal and oil to natural gas and renewable resources that is already in progress as a result of low natural gas prices, falling renewable energy technology costs, and state policy preferences. These resources have different operational characteristics than those the centrally organized electricity markets were originally designed for. Even natural gas, which is currently at historically low prices, is subject to supply constraints in some areas of the country and, therefore, subject to greater price volatility than traditional coal resources. This means operators must adjust to these new resource types and the challenges — and benefits — these resources bring with them.

As with earlier environmental regulations, resource adequacy and other reliability metrics are not expected to be significantly affected by GHG regulations as envisioned in the CPP, with some localized exceptions.[129] Most system operators have concluded that there will be minimal reliability concerns given the resource mix envisioned by the CPP. In fact, PJM found recently that currently announced retirements of existing resources would be enough for that region to comply with the CPP over a 20-year horizon while maintaining reliability and reducing congestion costs. In the short-term, reliability agreements (often called "reliability must run" agreements) can be used to maintain reliability while a transmission upgrade is being constructed to provide an alternate power source. Resources with "must-run" agreements are normally paid an uplift cost that is distributed proportionally to all loads in the region. While "must-run" agreements will distort energy market clearing prices (by inserting a high-priced resource in a lower spot in the bid stack), they do protect consumers against costlier interim resource decisions that would be implemented on an emergency basis.

The effect of environmental regulations on existing resources will be seen in at least three ways in energy markets, as distinct from capacity and ancillary services markets:

- First, resources that are not modified to reduce pollution may have very limited availability due to restrictions on operation. In some cases, the replacement resources will have higher costs and increase hourly energy market prices. In

[129] See, e.g., PJM's *EPA's Final Clean Power Plan: Compliance Pathways Economic and Reliability* Analysis. http://www.pjm.com/~/media/library/reports-notices/clean-power-plan/20160901-cpp-compliance-assessment.ashx; MISO's *Analysis of EPA's Final Clean Power Plan Study Report*, https://www.misoenergy.org/_layouts/miso/ecm/redirect.aspx?id=226815; and NERC's *Potential Reliability Impacts of EPA's Clean Power Plan.*

recent years, this price impact has been minimal due to the availability of gas-fired resources that have access to low-cost shale gas.

- Second, refurbished, compliant resources that are market generators will need to recover their new investment costs. If the offer price of these resources is below the price of the marginal resource (a gas resource in most hours across the country), the resource owners will hope to earn sufficient revenues in enough hours to cover the cost of their new investment — and consumers will see no change in their energy market costs. Alternatively, utility-owned, cost-of-service resources that cannot offer at or below the marginal resource price may seek direct recovery of their higher costs through their state regulatory commission process. In this situation, consumers would pay both the marginal energy price and the direct recovery charge on their monthly electricity bills.

- Third, some resources will retire, potentially allowing other, higher-priced resources to set the market price in some hours. The impact on consumers depends on how much higher, and how often, the higher-price resources set the marginal price.

All three of these impacts could increase hourly energy prices in the short term. The hours in which gas resources are the marginal resource setting the energy clearing price are expected to continue to expand. That trend will mean that the price of natural gas will continue to determine energy market prices, regardless of how many coal resources retire. To the extent clearing prices rise as a result of environmental regulations, this may enable additional renewable resources to enter the markets as their cost-effectiveness improves. Solar and wind installations, in particular, have seen dramatic cost reductions over the last decade.[130] Most industry experts anticipate future declines in overall cost. Battery and other storage technology costs are also trending downward.[131]

Overall, while environmental regulations may drive up the costs of certain types of resources and may lead to early retirement for some, those increases may be offset by low natural gas prices and falling renewable energy technology costs. For consumer advocates, the long-term goal is to have a least-cost mix of resources that will meet federal and state requirements for clean air and clean water while maintaining current reliability standards.

Over time, as the costs for these resources continue their downward trend, higher variable-cost fossil

[130] See Lazard 2015. Renewables Forecast, p. 10. https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-90/.
[131] See Lazard 2015. Storage Forecast, p. 17. https://www.lazard.com/perspective/levelized-cost-of-storage-analysis-10/.

fuels may eventually be replaced by lower variable-cost renewable resources as the marginal resources, and renewable resources will be setting the energy price in a small but increasing numbers of hours. Already we have seen the dramatic effects of high wind penetration during certain hours of the day in Texas, where in fall 2015 power producers were paying the system operator (in the form of negative prices) to take their electricity off their hands. This has also occurred in regions with abundant hydropower resources during periods of low demand.

Overall, while environmental regulations may drive up the costs of certain types of resources and may lead to early retirement for some, those increases may be offset by low natural gas prices and falling renewable energy technology costs. For consumer advocates, the long-term goal is to have a least-cost mix of resources that will meet federal and state requirements for clean air and clean water while maintaining current reliability standards.

3. What are the market impacts of integrating increasingly higher levels of renewable resources with zero marginal cost?

NASUCA's general response is that the integration of renewable resources with zero fuel costs will lower energy market prices and overall market revenues. What is uncertain is the extent that those lower energy prices will be offset by higher costs for capacity and ancillary services (primarily ramping and regulation services) that renewable resources impose.

Getting the capacity value "right" for variable resources will maximize consumer benefits and help satisfy both the "just and reasonable" and "not unduly discriminatory" standards of the Federal Power Act.

Increasing levels of resources with zero marginal cost will affect overall costs in several ways. Hourly spot energy prices may trend lower, occasionally reaching zero or even negative prices, over an increasing number of pricing intervals. Most baseload units (generation that today normally operates 24/7 over days or months) will experience revenue erosion. If renewable resource penetration reaches high levels (similar to Hawaii and Germany), many baseload units may become uneconomic. At high penetration levels, non-baseload resources will experience more significant revenue erosion as existing generation (often gas-fired) competes to provide a continually shrinking grid demand for energy. Conversely, peaking units may experience increased revenues to the extent that they can ramp up and down quickly in support of variable resources. Providers of other ancillary services such as regulation or volt-ampere reactive (VAR) to maintain voltage and stability may also see higher revenues.

One of the open questions in both PJM and ISO-New England is how capacity markets will give credit to new resources that operate differently than fossil fuel resources. Providing too high a capacity value or credit for variable resources will overstate their contributions to reliable grid operation and displace other resources that would otherwise be needed. Providing too low a capacity value or credit for variable resources will understate their contributions and lead to purchasing additional resources that would not be needed to meet reliability standards. Getting the capacity value "right" for variable resources will maximize consumer benefits and help satisfy both the "just and reasonable" and "not unduly discriminatory" standards of the Federal Power Act.

Historically, markets for ancillary services have not been a significant source of revenue for resources, especially when compared to energy and capacity revenues. However, for some resources, ancillary service revenues can be the major source of income. Battery storage for frequency regulation is one example. Properly valuing ancillary services to support the fast ramping and stability services that will be needed to integrate more variable resources will be an important role for markets to play going forward.

Market designs for ancillary services must recognize the system-balancing capabilities offered by a wide array of resources, including demand response. All such resources should be allowed to participate and should be paid for the value of their contribution to ancillary services. RTOs/ISOs will likely need to adapt their ancillary services markets as more asynchronous resources are connected to a historically synchronous resource base.[132] Technical solutions (e.g., transmission assets) can compensate for high levels of asynchronous resources over periods of time, but the specific engineering and costs of these solutions need to be explored further.

NASUCA members see a need for RTOs/ISOs and all stakeholders to better understand the overall impact of variable renewable energy resources on changes in revenue streams from all types of markets — energy, capacity and ancillary services — to ensure that market designs will provide reliable electricity service at the lowest cost to consumers. Too often, market designs are focused on a single issue (such as compensation for fast ramping resources) in isolation from other market revenues available to the resources. Comprehensive and transparent analyses by the independent RTO/ISO would help provide this better understanding.

4. Are today's market designs adequate to acquire the flexible resources needed to integrate increasing levels of variable energy resources at least cost?

Current grid markets and mechanisms are adequate and robust for the existing penetration levels of variable energy resources, but as penetration levels escalate in the coming years, current approaches will need to be modified to accommodate both a greater need for

[132] Asynchronous resources such as wind, solar and some hydro resources lack the machine-mass (inertia) of a coal, nuclear or gas turbine and are therefore harder to regulate. The machine-mass, by providing VARs, helps to maintain the stability of the current on the wires that transmit the electricity.

flexible resources and a larger variety of resources that can provide these necessary services.

Grid operators require a wide range of services in addition to energy and capacity. These ancillary services fall into three general buckets: contingency reserves, ramping reserves and stability resources (see Figure 4.1). Contingency reserves are the traditional reserves needed to restore the system after a significant contingency event such as the sudden loss of a generation unit or transmission line. Ramping reserves are needed over particular hours of the day, due to gradual changes in demand during mornings and evenings, or for particular events within an hour, due to sudden fluctuations in variable generation or demand. Stability resources are very fast responding resources that maintain voltage and provide reactive power with normal, momentary fluctuations in supply and demand. [133]

Consumer advocates support market designs that enable demand response to compete on an equal basis with other resources to the extent that demand response can provide a comparable and cost-effective service.

Existing markets procure adequate supplies of these categories of ancillary services for today's resource mix. Demand response has become an important resource for reducing system stress by lowering demand at critical times to lessen the burden on generating resources, including contingency reserves — and for lowering market prices. On some systems, demand response may be able to provide an expanded role for both contingency reserves and ramping reserves using current technologies. Advanced metering or other technologies may enable aggregated customer demand response from many small users to provide ramping or stability services.

Consumer advocates support market designs that enable demand response to compete on an equal basis with other resources to the extent that demand response can provide a comparable and cost-effective service. Some market regions have adopted market rules enabling demand response resources to participate in capacity, energy and ancillary services markets. For example, PJM allows for demand response resources as small as 100 kilowatts (kW) to participate in its markets. Conversely, MISO sets a 5 megawatt (MW) minimum size requirement that creates a significant barrier to increased participation of demand response in that region.

Current penetration levels of renewable resources do not typically create significant operational or market issues. Some studies have shown that small increases in penetration

[133] These are general descriptions of the types of services that are needed by all electric grids. The names used for them vary between regions.

levels can generally be accommodated by current markets and electric grids.[134] In centrally-organized energy markets, the use of locational marginal prices (LMP) can help allocate some costs of reserves to a subset of customers rather than all customers on the system. Current market operations co-optimize the selection of energy and contingency reserves to achieve a daily least-cost mix of resources that is reflected in the LMP value for specific locations. Expanding that co-optimization to include ramping and stability services may become an attractive option for addressing the additional needs of a system with more variable resources.

Assuming that renewable resources increase over time due to technological advances and state policies that support low- or zero-emission resources, system operators may need to expand the existing mechanisms for procuring these ancillary services resources, or develop some new categories of resources and new purchase mechanisms. An important issue for NASUCA members is how the costs for these expanded or new services are allocated. Some expanded services may be directly tied to a particular resource type. In that case, the costs can be appropriately allocated to those specific resources. Other services may support overall grid operation issues and are more appropriately shared among all grid customers.

Traditionally, new generation resources have been allocated the costs of specific upgrades needed to integrate them into the overall system. This could include new lines and new equipment to cover overloads, potential short-circuit issues, and general stability needs. Once integrated, however, the services needed to address daily operational issues regarding contingencies, ramping, and system stability are shared by all resources on the system, and their costs are shared as well.

Recent changes to the FERC pro-forma Large Generator Interconnection Agreement and Small Generator Interconnection Agreement require that wind generation units provide a minimum level of regulation service (to control for voltage and stability issues) with grid operators.[135] This change is meant to capture a reasonable amount of the cost that these types of resources are imposing on the system due to their asynchronous nature. FERC determined that this regulation technology was readily available to wind manufacturers at a reasonable cost. The amount of regulation service required will be provided and paid for by each wind generator. Additional daily regulation for system operation will still be needed on a moment-to-moment basis, and those costs will continue to be socialized under current operating rules.

[134] See e.g., National Renewable Energy Laboratory studies, http://www.nrel.gov/grid/ergis.html; Northern States Power Study. 2014. https://www.xcelenergy.com/staticfiles/xe/PDF/Regulatory/16-App-M-NSP-Wind-Integration-Study-January-2015.pdf; PJM study. 2014. http://www.pjm.com/~/media/committees-groups/subcommittees/irs/postings/pris-executive-summary.ashx; and New England study. 2010. http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/index.html.

[135] FERC Order 827. 155 FERC ¶ 61,277. June 16, 2016. https://www.iso-ne.com/static-assets/documents/2016/07/2016_07_26_tca03_order.pdf.

As mentioned earlier in response to Question 3, one specific challenge occurs when very large quantities of solar, wind, batteries and other non-combustion resources are integrated into the grid: the need to maintain the stability of the grid as these variable resources replace traditional generation resources such as coal, nuclear and gas. There are technical options to address this shift, such as synchronous condensers, flexible alternating current transmission system devices, and power factor correction capacitors. The challenge for RTOs/ISOs is to develop market designs that can use competitive offers to select the least cost mix of resources that can provide the necessary support, and to establish proper allocation of these costs.

First, all resources, whether owned by merchant generators, utilities or end-use customers — and whether supported by market prices alone, with ratepayer support, or with specific subsidies or incentives — should be evaluated for the grid services they can provide and, if appropriate, be allowed to compete in centrally organized markets and be paid for those services. Second, no resource type should be excluded from centrally organized markets or grid compensation mechanisms simply because the resource has different operating characteristics or receives support from utility or public policy programs.

Conclusions

NASUCA members have six concluding comments that apply to the four questions posed in this report.

First, all resources, whether owned by merchant generators, utilities or end-use customers — and whether supported by market prices alone, with ratepayer support, or with specific subsidies or incentives — should be evaluated for the grid services they can provide and, if appropriate, be allowed to compete in centrally organized markets and be paid for those services.

Second, no resource type should be excluded from centrally organized markets or grid compensation mechanisms simply because the resource has different operating characteristics or receives support from utility or public policy programs.

Third, the costs and benefits of resources must be appropriately valued, and the allocation of costs and benefits to some or all consumers should be determined based on a transparent analysis with state participant input.

Fourth, most of the solutions to address the four questions addressed in this report will be found in the expansion or development of new mechanisms to acquire a wider variety of ancillary services, particularly ramping and regulation services.

[M]ost of the solutions to address the four questions addressed in this report will be found in the expansion or development of new mechanisms to acquire a wider variety of ancillary services, particularly ramping and regulation services.

Fifth, where markets are used to supply electricity to serve customers, the retail customer's interest in reliable and affordable electric service is best served by ensuring that markets are efficient and transparent. Administrative policies and market rules that are designed to harmonize state policies and preferences for electricity supply should be designed such that the efficiency and transparency of the markets are maintained.

Finally, NASUCA believes that its members must be able to effectively and meaningfully participate in FERC-approved RTO/ISO stakeholder processes to provide their perspective on market rules and system planning options, given the significant cost impacts of these decisions on retail electricity consumers. This participation should be supported in a manner similar to the support provided by RTOs/ISOs to state regulatory commissions.