American Public Power Association
Statement
Quadrennial Energy Review
Second Installment
Electricity: Generation to End-Use
Boston Regional Meeting
April 15, 2016

The American Public Power Association (APPA) is the national service organization for the more than 2,000 not-for-profit, community-owned electric utilities in the United States. Collectively, these utilities serve more than 48 million Americans in 49 states (all but Hawaii).

APPA was created in 1940 as a nonprofit, non-partisan organization to advance the public policy interests of its members and their customers. We assist our members in providing reliable electric service at a reasonable price with appropriate environmental stewardship. Most public power utilities are owned by municipalities, with others owned by counties, public utility districts, and states. APPA members also include joint action agencies (state and regional entities formed by public power utilities to provide them wholesale power supply and other services) and state, regional, and local associations that have purposes similar to APPA.

Public power utilities deliver electricity to one of every seven electricity customers. We serve some of the nation's largest cities, including Los Angeles, CA; San Antonio, TX; Austin, TX; Jacksonville, FL; and Memphis, TN. However, most public power utilities serve small communities of 10,000 people or less.

In terms of public power utilities' power generation portfolio, in 2014 these utilities generated 173.3 million megawatt-hours (MWhs) of electricity from coal; 80.2 million MWhs from natural gas; 68.2 MWhs million from nuclear; 66.8 million MWhs from hydropower; and 8.7 million MWhs from other sources such as non-hydropower renewable energy like wind, solar, and geothermal. It is important to note, however, that public power utilities supply approximately 15 percent of electricity to end-users in the United States, but they only produce 10 percent of the megawatt-hours generated. To make up the difference, public power utilities purchase power at wholesale from other entities such as other public power utilities (some of which do have extra power to sell), investor-owned utilities, independent power producers, rural electric cooperatives, federal power marketing administrations, and the not-for-profit, federally owned Tennessee Valley Authority.

APPA appreciates the opportunity to provide the following statement for the Department of Energy's (DOE) Quadrennial Energy Review (QER) second installment Boston regional meeting. This meeting will cover important issues to public power within the PJM Interconnection (PJM), ISO New England (ISO-NE), and the New York ISO (NYISO) operated wholesale electricity markets. We have provided, and will continue to provide, DOE with more extensive and in-depth analyses, reports, testimony, and other documents, just as we did with the first installment of the QER. Please see the glossary of terms following this statement defining the highlighted terms below.

These submissions have and will address the following, among other issues: 1) the Environmental Protection Agency's (**EPA's) Clean Power Plan** and its impacts on public power; 2) **wholesale electricity** and **mandatory capacity markets**; and 3) **distributed generation**. Many public power utilities have been providing highly reliable and affordable electric service for over 100 years, and have improved and evolved over those years as the industry has evolved. Given public power's customer orientation and not-for-profit structure, we are confident that public power utilities will continue to provide affordable, reliable electric power well into the future if not constrained by inappropriate regulation.

APPA is especially pleased to have two of its members testify today. Gil Quiniones, President & CEO, New York Power Authority, will be participating on the first panel to discuss bulk power generation and transmission. Edward Tatum, Vice President, Transmission, American Municipal Power, will be participating on the third panel to discuss how to ensure **resource adequacy** within the three electricity markets being discussed today.

Wholesale Electricity Markets

In the Northeast and Mid-Atlantic regions, resource adequacy, the types of generation and demand-side resources that are developed, and the costs of ensuring such resources are in place to meet the expected demand for electricity are all heavily influenced by the wholesale markets operated by PJM, ISO-NE and NYISO, especially the mandatory capacity markets. These markets have a high degree of influence over the **bulk power system** and resource adequacy because many of the for-profit, investor-owned utilities have been restructured (essentially breaking them up into separate distribution, generation, and transmission entities), producing a large pool of merchant generation whose prices and earnings are no longer regulated by state utility commissions. In contrast, public power utilities remain fully accountable to their local governing bodies.

APPA has expressed strong concerns over the past 10 years about the restructured wholesale electricity markets operated by Regional Transmission Organizations (RTOs). Many APPA members face the complexity and costs of operating in these markets on a day-to-day basis. Adding to our concerns are the time-consuming and resource intensive stakeholder processes, and the lack of transparency in the governance processes of some of these RTOs. The most problematic of the RTO-operated markets are the mandatory capacity markets that are operated by PJM, ISO-NE and parts of the NYISO.

In the context of **wholesale electricity markets**, a capacity market is a mechanism to provide revenue to a power plant owner to stand ready to supply power when needed, or to customers who agree to curtail their load (i.e., demand response). An electric power utility or other load-serving entity (LSE) (which is an entity that provides electricity to end-users, including a utility or alternative supplier serving a utility's customers) purchases or owns capacity to ensure a reliable supply of power during peaks in demand (generally the hottest and coldest times of the year). The LSE needs to have in place sufficient capacity to meet the projected peak demand plus a reserve margin, as determined by regional reliability entities. This helps ensure that the regional grid operator can "keep the lights on" and adhere to the statutory obligations under the Federal Power Act's Section 215 governing reliability.

In these mandatory markets, **capacity** must be bought and sold through the RTO market. Capacity that is owned or contracted bilaterally must still be offered into, and must clear, the **capacity auctions**. The price paid for capacity purchased through the auction is set by the RTO. PJM and ISO-NE both operate a "forward" market where capacity is procured three years in advance for a one-year period. The capacity auctions in the NYISO are shorter-term and are procured close to the period when the capacity will be needed.

While these markets are described as "competitive," they are, instead, highly mechanized, centrally administered constructs governed by thousands of pages of complex rules. Transactions in these markets are opaque, with little meaningful data available to the public. RTO-operated wholesale electricity markets are ostensibly regulated by the Federal Energy Regulatory Commission (FERC), but FERC heavily defers to the RTOs to manage the "markets" under their purview.

LSEs in regions without mandatory capacity markets meet their reliability requirements through ownership and bilateral contracts – and generators recoup the costs of providing capacity through these mechanisms. In contrast to the RTO-operated mandatory capacity markets, such long-term contracts are generally procured and negotiated through competitive processes. Procuring capacity through long-term bilateral contracts and ownership is important for maintaining adequate capacity, and necessary to obtain financing for new power plants, including carbon-free generation such as nuclear and renewable energy projects.

Difficulties with Mandatory Capacity Markets

Capacity prices in mandatory capacity markets have increased the cost of electricity and account for a growing share of the total electricity costs paid by consumers and businesses. This has occurred with only a relatively small amount of new power generation being put into service – resulting in a high cost with little benefit, as discussed in more detail below.

In theory, capacity payments cover a power plant's fixed capital costs and other costs not recovered through electricity sales in energy and other markets. But these markets have not demonstrated that they incentivize investment in either the types of generation necessary to achieve a reliable and diverse supply of power, or generation where it is most needed on the grid. Moreover, they do not exhibit any of the features of competitive markets, such as an absence of barriers to entry of suppliers, prices that closely reflect costs, and availability of information, and are instead administrative constructs requiring elaborate rules and processes, and include such anti-competitive rules as price floors. The RTOs have continually tweaked the rules in an attempt to address increasing reliability concerns in light of: pending coal and nuclear retirements; an increased reliance on natural gas; poor performance of generators during the 2014 winter; and new environmental regulations. Often these rule changes have not improved the markets, but instead have simply increased the revenue paid to owners of existing generation resources, who have a strong interest in maintaining a regime that limits competition from new entrants and props up capacity prices, as described herein.

<u>High Costs without Corresponding Benefits</u>

The costs of capacity markets are high, and while APPA recognizes that generation capacity is capital-intensive, the costs do not appear to be justified by spending on needed resources. To illustrate, in the PJM capacity market, known as the Reliability Pricing Model (RPM), approximately $88 billion has been paid or pledged to capacity suppliers through the middle of 2019. This works out to approximately $1,500 per man, woman, and child living in PJM's 13-state area. In 2014, the RPM added $100 per year to the average electric bill of a homeowner, $765 for a retail establishment, and $15,000 for an industrial facility. But only a small portion of the $88 billion was spent or committed is financing new generation capacity. More than 90 percent of the capacity procured is from *existing* power plants, and only two percent is from new and "reactivated" generation resources. **Demand response** and energy efficiency account for only five percent of the capacity.

In ISO-New England, the capacity market costs increased from about $1 billion per year for the first seven auctions, to $3 and $4 billion in the eighth and ninth auctions, held in 2014 and 2015. Allegations of market manipulation in the eighth auction, held in February 2014, led Chairman Norman Bay (then a commissioner) and Commissioner Tony Clark to conclude that the results of that auction should not be approved, finding that "there is evidence suggesting the exercise of market power, and it is uncontroverted that the market power, if it existed, was not mitigated."

In the most recent auction, held in February 2016, costs continued to be significant, totaling $3 billion for the 2019-2020 delivery year. Just four percent of the cleared resources were new generation, the bulk of which is comprised of dual fuel natural gas and oil units, which will likely burn higher emission oil during times of tight natural gas supplies. Renewable resources accounted for less than one percent, and demand response totaled eight percent of the capacity clearing in the auction.

<u>Impediments to New Supply</u>

Not only are the costs significant, but highly problematic and anti-competitive changes to capacity market rules in recent years can restrict new entry. Such rules fall under the categories of "**buyer side mitigation**" or "**minimum offer price rules**." The impetus for these changes began about five years ago when several states located within RTOs became frustrated with the lack of new power generation being developed despite billions of dollars spent on capacity payments. These states sought to take control of their energy resource future and protect their residents from high electricity prices. New Jersey, Maryland, and Connecticut all took steps to establish competitive bidding processes for the procurement of capacity for long-term bilateral contracts. In January 2011, New Jersey Governor Chris Christie signed legislation to create a competitive bidding process for long-term fixed-price contracts for new power plants and, at about the same time, the Maryland Public Service Commission issued an order to procure long-term contracts for new capacity.

Fearful of the *lower* prices that would result from the entry of new generation constructed under these state efforts, owners of existing power plants sought to block this competition. (Never mind that the creation of the eastern RTOs was predicated on the ability of these new "markets" to lower prices in high-cost regions.) PJM responded with a similar proposal, and in 2011, FERC approved changes to PJM's "minimum offer price rule" (MOPR). This more stringent rule requires PJM to replace low- or zero-price offers from new natural gas plants with higher price offers, making it more difficult for these new plants to "clear" the capacity auctions.

ISO-NE, in accordance with an order from FERC, modified its rules to create a similar MOPR to PJM's in December 2012, despite the absence of support from stakeholders in the region, and received approval from FERC in February 2013. The ISO-NE minimum offer price applies to all resources, including renewable energy (other than a small exemption). In both PJM and ISO-NE, FERC actually reversed carefully negotiated provisions agreed to when the markets were created that guaranteed that **self-supply** resources could clear the auctions. The PJM and ISO-NE orders were appealed to the U.S. Court of Appeals for the Third Circuit. Unfortunately, the court ruled that the self-supply appeal was mooted by FERC's approval of a compromise for a self-supply exemption (described later), and also rejected the states' appeals of the MOPR rule.

In separate cases, federal district courts in Maryland and New Jersey invalidated the Maryland order and New Jersey law, respectively, because, the courts stated, FERC has jurisdiction over wholesale power rates and states cannot take actions that impact wholesale power markets. These decisions were appealed and upheld by the U.S. Courts of Appeals for the Third and Fourth Circuits. In response to petitions from the New Jersey and Maryland state commissions and two independent power producers, the U.S. Supreme Court agreed to review the Circuit Court decisions, and has not yet issued a decision.

A second set of problematic changes to the capacity markets, referred to as "capacity performance" in PJM or "performance incentives" in ISO-NE, will also significantly increase capacity costs and further constrain supply. In New England, generators that are not operating or not providing reserves during scarcity conditions are subject to stringent penalties, encouraging resources not meeting this requirement to face significantly higher costs and submit higher price offers for capacity. PJM has placed new capacity performance requirements on all resources that wish to participate in the capacity auction similarly requiring resources to be available during emergency periods. These rules carried significant capacity price increases in both RTOs, but especially in PJM where the offer cap was lifted, thus allowing capacity resources to bid in much greater prices than needed to meet the capacity performance obligations. An APPA-commissioned analysis of the PJM capacity performance rule found that the new rule will increase capacity costs by $7.3 billion over three years with no discernible benefit to reliability. Moreover, these rules will greatly disadvantage hydropower and other forms of renewable energy, demand response, and energy efficiency programs, further constraining supply.

Impacts on Public Power and States

Buyer-side mitigation rules make it more difficult for public power utilities, rural electric cooperatives and state agencies to determine and pursue their future electric resource needs while meeting public policy goals. Given that the states will be the locus of implementation of the Clean Power Plan, such impediments will create difficulties for the states in their efforts to develop a new portfolio of lower-carbon emission resources.

There have been recent positive developments that may minimize the negative impacts on public power of the buyer-side mitigation rules. Negotiations among merchant generators, industrial customers, and public power and cooperative utilities in 2012 resulted in an agreement providing for a MOPR exemption for both competitive entry and self-supply resources that meet certain criteria. This agreement was approved by FERC in May 2013. The competitive entry exemption applies to resources without any support from a utility customer charge or payments from a governmental entity. Exempt self-supply resources are those owned or procured by LSEs who have long standing business models (i.e., public power, cooperative, and vertically-integrated utilities) and who can meet certain "net-short" or "net-long" thresholds. Net-short, net-long means that the exempt resource would not result in the LSE buying substantially more capacity in the capacity markets than they sell (net-short) or selling substantially more capacity than they buy (net-long). Such thresholds are intended to demonstrate that the LSE would not have any financial incentive to exercise "buyer-side market power." In January of this year, the PJM Power Providers Group (P3) and NRG appealed the FERC Order approving a self-supply exemption from the MOPR in the Court of Appeals for the DC Circuit.

State-sponsored resources are still not subject to any exemption in PJM unless they can demonstrate that the resource was procured through a process that was open to all generation types, an unrealistic scenario given the need for states to be able to determine what resources best meet regulatory and policy needs. In NYISO, self-supply exemptions were granted by FERC in two separate 2015 dockets. First, FERC approved a competitive entry exemption for resources that are offered into the auction, but receive no payments from bilateral contracts or other "subsidies." Second, FERC later approved exemptions for self-supplied resources and a limited amount of renewable energy, the details of which are still being determined in the ISO stakeholder process. Resources eligible for the self-supply exemption would be required to meet net-short and net-long thresholds as in the PJM MOPR self-supply exemption.

These self-supply exemptions represent a significant improvement to the buyer-side mitigation rules, but still are not a return to the complete exemption for self-supply agreed to in the original design of the capacity markets in PJM and ISO-NE (which still does not have a self-supply exemption) and later overturned by FERC. Self-supply is one of the few viable alternatives that public power has to the RTO-operated mandatory capacity markets, and therefore greater certainty of this right is critical for public power.

Moreover, public power has a critical role to play in the country's energy future. As Gil Quiniones states regarding bulk power generation and transmission, "projects like these show that as the world progresses into the 21st century and our energy industry continues to evolve, public power can help lead the way in innovative technology and policy solutions that address the challenges we face. Through engaging with the many public power agencies throughout the nation, we as leaders can learn from the successes of our peers and adapt the solutions to our own context."

Conclusion

APPA has long advocated for fundamental reforms that would transition from mandatory capacity markets to voluntary residual markets, with the primary procurement of capacity conducted by states and local public power and cooperative utilities through bilateral contracts. As Ed Tatum notes in his statement, these markets "do not work well to determine or incent the resources needed to be built, retired or retained. Our focus should be to improve the functioning of the energy markets, reduce reliance on resource adequacy constructs, and shift to a different construct for resource adequacy and planning."

APPA is ready to work with DOE to address the shortcomings of these administrative constructs. We want to thank you again for the opportunity to address the QER this morning and allow our members to share their successes and concerns with you. APPA hopes that the views expressed by this statement will be fully considered by DOE as you develop the second installment. APPA and its members stand committed to working with you.

Glossary of Terms

Bulk Power System: The facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and the electric energy from generation facilities needed to maintain transmission system reliability, not including facilities used in the local distribution of electric energy.

Buyer-side mitigation: A category of rules used in some RTO capacity markets to prevent the theoretical and unproven scenario whereby a buyer of capacity would construct a new generation resource that would otherwise be uneconomic, solely for the purpose of selling that resource into the capacity market and lowering prices for the capacity purchased by that entity.

Capacity: The maximum electricity output, expressed in megawatts, that a power plant can produce under specific conditions or the maximum amount of megawatts of demand response available (see definition below).

Capacity Auction: A mechanism operated by the RTO where capacity is procured for a given period of time, i.e.; one year, beginning either in the future, i.e.; three years after the auction, or in the near term, i.e.; the next month. Based on offers from capacity suppliers and an administratively constructed demand curve, the auction determines the amount of capacity to be procured within a geographic region at a single price.

Demand Response: Reductions in electric use by an end-user, such as a factory, from normal consumption patterns when required to maintain system reliability (in the case of a capacity resource), or in response to changes in the price of electricity or to incentive payments.

Distributed Generation Small-scale energy supply systems — thermal, renewable, fuel cell, and energy storage technologies — that are located on or close to the site of energy consumption. These resources may be interconnected to the electric distribution system on the utility or customer side of the meter as opposed to larger installations interconnected to the transmission system.

EPA's Clean Power Plan: EPA's rule, published in 2015, establishing final emission guidelines for states to follow in developing plans to reduce greenhouse gas emissions from existing fossil fuel-fired electric generating units established under the authority of the Clean Air Act Section 111(d). The U.S. Supreme Court granted a stay of the rule on February 9, 2016.

Wholesale Electricity Markets: Markets where energy sales are made between energy producers, or marketers and brokers selling such energy on their behalf, and utility companies that provide electricity to customers, as well as directly to high-volume end-users.

Mandatory Capacity Markets: A type of capacity market where all capacity within the Regional Transmission Organization (RTO) must be bought and sold through that construct. Capacity that is owned or contracted for bilaterally still must be offered into and clear the capacity auctions.

Minimum Offer Price Rule: The most common type of Buyer-Side Mitigation Rule (defined above) whereby the RTO has the ability to impose a minimum price at which a new resource must be offered into a capacity market auction.

Resource Adequacy: Sufficient electric generation and demand-response available to meet the expected demand for electricity, plus a reserve margin for contingencies.

Self-supply: The practice of a local utility meeting the electricity requirements of customers within its service territory through direct ownership of electric generation facilities and/or competitively-procured bilateral contracts for resources owned by third parties.

State-sponsored Resources: Capacity resources contracted for by the regulated distribution utilities pursuant to an order of the state public service commission.

Comments of Edward D. Tatum Jr.
Vice President of Transmission
American Municipal Power

U.S. Department of Energy Quadrennial Energy Review
Second Installment
Electricity: Generation to End Use
Stakeholder Meeting #2: Boston MA
April 15, 2016

Panel 3: Ensuring Resource Adequacy in RTO/ISO Markets

American Municipal Power is the non-profit wholesale power supplier and services provider for 132 member municipal electric systems. We cover 9 states over two RTOs. Our members serve over 640,000 meters. We have approximately 1,900 MW's of owned generation with a system peak load of approximately 3,400 MW's. We are a transmission dependent utility. We are a member of APPA. Our geographic scope and resource mix provide AMP with important insights and perspectives on "organized" markets.

Public Power supports wholesale energy markets when they work well and are competitive. This generally occurs when there is little or no transmission congestion and/or when fuel prices are not volatile. The energy markets are intended to improve the efficiency and lower the cost of the dispatch of existing resources, but they ***do not*** work well to determine or incent the resources needed to be built, retired or retained. Our focus should be to improve the functioning of the energy markets, reduce reliance on resource adequacy constructs, and shift to a different construct for resource adequacy and planning. And, as always, we need to balance consumer perspectives with market perspectives.

Administrative Resource Adequacy Constructs originally developed to address the "missing money" have never worked well. This is evidenced by the continual changes to these constructs[1] and the volatile results of past auctions[2]. And PJM's most recent manifestation inappropriately incorporates performance attributes that would be better addressed in the Energy and Ancillary Service Markets. These constructs are needlessly complex and take us further away from the vision of "competitive markets" upon which industry restructuring was

[1] Since 2010, there have been at least 24 filed revisions to PJM's Reliability Pricing Model
[2] See PJM's 2018/19 Base Residual Auction results to track price volatility since inception

based. What was once intended to be a backstop residual, temporary construct has morphed into a primary revenue source for supply. These constructs and their evolution are a reluctant admission by competitive market proponents that the market is not working.

Additionally, these administrative constructs focus on revenue enhancing strategies rather than achieving an optimal resource mix at the lowest cost to consumers. The result has been high costs to consumers, without the benefits to justify those costs. Determining and procuring needed resources should be done through long-term planning and a portfolio of contracts of different lengths for different types of resources.

The key to workably competitive markets lies in FERC's efforts surrounding price formation, specifically the need for better models that accurately capture all known constraints and more rigorous cost development as inputs into the improved models. And it goes without saying that any energy market improvements should seek to provide the lowest overall cost to consumers while protecting consumers from those who would seek to exercise market power.

DOE and FERC should vigorously pursue the recommendation from the DOE Multi-year assessment[3] for improved models and its price formation initiatives.

Additionally, FERC should resist any additional changes to these failed Capacity Constructs. Rather, FERC should avail itself of a much simpler construct (as described by APPA) that comports with the expectations of the financial community for long-term contracts. For example, a simpler and more effective approach could be to simply assign each load-serving entity (LSE), regardless of whether they are in a retail choice state, a long-term capacity obligation that would include a reserve margin above load as well as meaningful penalties for non-performance. The LSE could then determine an optimal and diverse mix of resources to meet policy goals and minimize costs to their customers.[4]

[3] November 2015, Department of Energy Grid Modernization Multi-Year Program Plan
[4] See "Solving the Electricity Capacity Market Puzzle: The BiCap Approach" 2013, Navigant Consulting, Inc.

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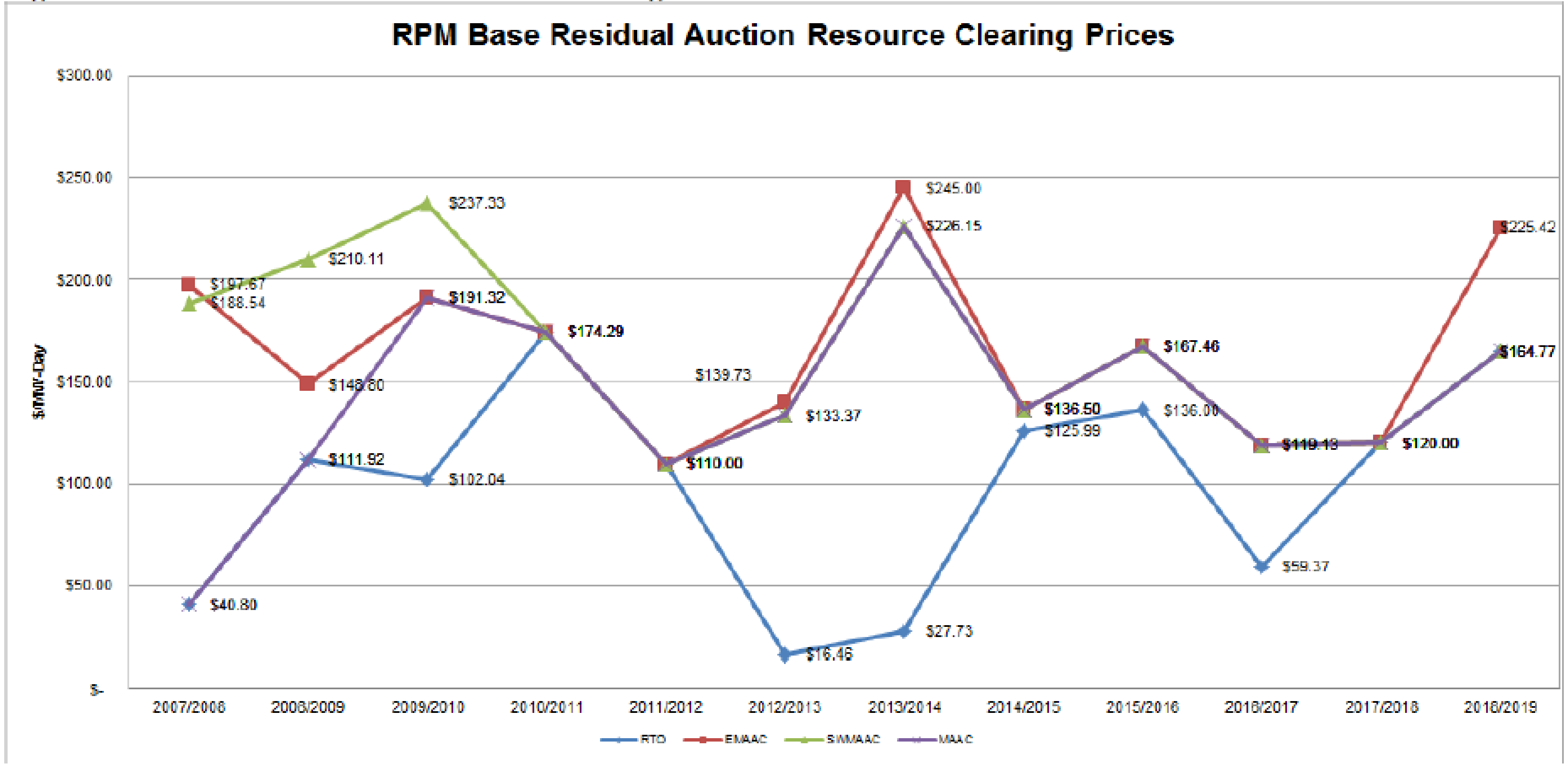
Panel 3 Ensuring Resource Adequacy in RTO/ISO markets

Attachments

- 2018/2019 RPM Base Residual Auction Results, PJM
- "Solving the Electricity Capacity Market Puzzle: The BiCap Approach", Navigant Economics 2013
- American Public Power Association Statement (APPA), Quadrennial Energy Review, Second Installment, Electricity: Generation to End-Use, Boston Regional Meeting, April 15, 2016
- "PJM's "Capacity Performance" Tariff Changes: Estimated Impact on the Cost of Capacity", APPA
- "Capacity Markets Do Not Incent New Electric Generation, Market Reforms for Reliable and Affordable Electricity", 2015 Update, APPA
- "America's Electricity Generation Capacity", 2016 Update, APPA
- February 10, 2014 Letter to the Federal Energy Regulatory Commission on Centralized Capacity Markets in Reginal Transmission Organizations and Independent System Operators, Docket No. AD13-7-000,
- "Ensuring Adequate Power Supplies for Tomorrow's Electricity Needs", Christensen Associates Energy Consulting LLC, June 16, 2014

2018/2019 RPM Base Residual Auction Results

Figure 2 – Base Residual Auction Resource Clearing Prices



*2014/2015 through 2018/2019 Prices reflect the Annual Resource Clearing Prices.

Solving the Electricity Capacity Market Puzzle: The BiCap Approach

EXECUTIVE SUMMARY

Every organized wholesale electricity market has a different approach to solving the capacity market puzzle, and each fails in what should be its main priority: using the forces of market competition to deliver adequate capacity at a reasonable cost. Billions of dollars pass from consumers to suppliers based on the assumption that this revenue maintains system operations over the long term and encourages investment. There is scant evidence to support these conclusions. The existing capacity payment mechanisms — which some call "markets" — are a mad conflagration of administrative processes overlaid upon bidding constrictions. We can do much better.

While there are many variations, current capacity markets generally involve placing obligations on load serving entities (LSEs) to acquire capacity on a short-term basis. Regional Reliability Organizations (RROs)[1] administer auctions for the sale of capacity and manage congestion issues, while preserving the ability for customers to change LSEs. This approach was built on the premise that capacity obligations should be tied to the provision of energy, and seemed a natural combination in the drive to competitive markets. With customers having the ability to change suppliers, however, LSEs are not in position to sign the long-term contracts needed by suppliers to borrow money cheaply.

There is a better alternative, a <u>Bi</u>lateral <u>Ca</u>pacity (BiCap) market with buyers who can make long-term commitments. Under BiCap, the existing RRO-administered, auction-based market is eliminated. The capacity obligations become the responsibility of the distribution providers (DPs), which are the regulated monopoly providers of the interconnections to retail customers — the wires companies. The DPs have captive customers for the long term and this places them in a position to be able to sign the long-term capacity contracts that will efficiently bring down costs. With BiCap, each DP will manage a portfolio of capacity rights from suppliers and have the flexibility to establish contract terms that reflect the needs of each supplier.

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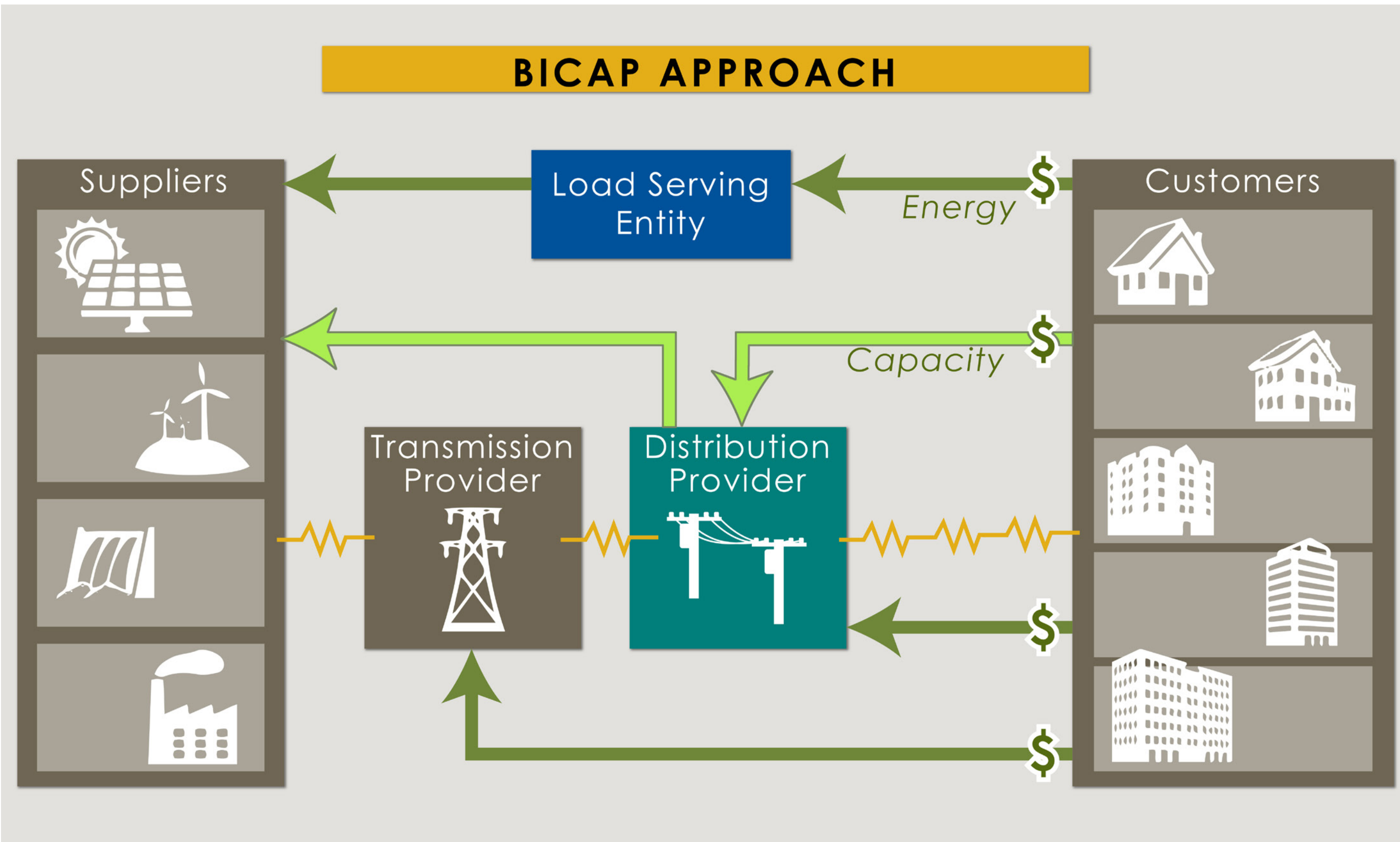
Under BiCap, the wires companies are responsible for purchasing capacity. They have the committed relationships with customers that allow them to make long-term commitments. This allows contracting to reduce borrowing costs, targeting new supply resources to meet local problems and direct comparison with transmission alternatives.

1 There is some overlap between the role of the Regional Reliability Organization, the Regional Transmission Organization (RTO) and Independent System Operator (ISO) on these issues, with distinctions that vary across the country. These distinctions are not important in this discussion. For this paper, RRO will be used loosely to apply to the combined responsibilities of RROs, RTOs and ISOs with respect to capacity obligations and markets.

NAVIGANT ECONOMICS



Bicap provides needed flexibility:

» A new generator could sign a long term contract.

» The DP could work with a supplier to manage the retirement of an old generator.

» Locational congestion problems can be addressed by signing contracts for supply in the area where it will provide the most value.

» The DP will also be in a position to manage load pocket needs through direct comparison of generation and transmission options.

Shifting the obligation for procuring capacity from LSEs to DPs will sound heretical to some, particularly if characterized as a step backwards from competitive markets. But it is not. It does not change the underlying operation of the system or limit the means by which capacity resources can be deployed to maintain reliability. Capacity suppliers remain unregulated. Competition among suppliers is enhanced. The cost of capital for new generation projects is reduced because the long-term contracts give lenders more confidence of positive cash flow in the future. And it will be easier to balance transmission upgrades against generation alternatives. All of these factors will increase system supply adequacy while lowering costs to consumers.

NERC DEFINITIONS

Distribution Provider (DP): Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages without a DP, they will be a DP for the purpose of obtaining their own capacity.

Load Serving Entity (LSE): Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.

Regional Reliability Organization (RRO): An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure.

THE PROBLEM WITH TODAY'S CAPACITY MARKETS

Electricity is a unique product. Energy markets, involving the sale of electric energy (measured in MWh) have evolved through careful refinements to deal with the problems associated with the inability to store electricity and the challenges imposed by transmission limits. The resulting markets are efficient in optimizing short term supply, but have been challenged in managing long-term supply incentives. This is the so-called "missing money" problem. All competitive electricity markets deal with this problem to some extent, typically by creating a capacity product (measured in MW) that allows for additional compensation to suppliers and places the burden of cost on LSEs, who then pass this cost on to their customers. In competitive markets, customers are able to switch LSEs. This ability for customers to switch suppliers has made it virtually impossible for LSEs to take on long-term obligations to purchase capacity. Most competitive electricity markets attempt to address this problem by having the RROs run auctions that allow LSEs to purchase capacity in the short-run and require suppliers to participate. The resulting markets provide for the huge transfer of wealth from customers to suppliers in quantities that roughly match expectations of the "missing money".

These markets are not working well. The problems manifest themselves in many ways. The money being spent by LSEs is not providing clear and efficient signals for market entry where it is needed. A single new generator in a high-construction-cost area will resolve load pocket reliability problems, but a potential new entrant has no confidence that long-term compensation will be provided. More generally, the price signals are of such a short duration that new entrants are understandably skittish regardless of the current needs for capacity. Even when it is obvious how the timing of things such as transmission upgrades, unit retirements and new unit construction should be coordinated, it is nearly impossible to get price signals in today's markets to achieve the desired outcome. Current markets are rife with accusations of both buyer and seller market power. There are many who feel that customers are not getting a reliable electricity service for the money spent. These and other problems have led many in industry and regulatory circles to conclude that change is needed.

SOLVING THE PROBLEM BY TRANSFERRING PURCHASING RESPONSIBILITY

The BiCap approach transfers the obligation for purchasing capacity from the LSEs to the DP. In fact, BiCap relieves LSEs of any obligation to procure or otherwise deal with capacity obligations. With this simple, albeit dramatic change, the obligation for capacity is transferred from entities inherently focused on the short term and caught in the cross-fire of competition, to entities with a long-term planning horizon and the ability to deal with capacity issues in a much more predictable and cost-effective manner.

Currently, the roles of the DPs vary widely in the electricity industry. Some are vertically-integrated investor-owned utilities with an obligation to provide energy services. Some only have the responsibility for the distribution system, leaving energy supply to competitive suppliers. Some are municipalities or rural cooperatives. In all cases they are the monopoly-providers of the last mile of the electric distribution network to the customer. If the DPs are for-profit companies, they provide this "wires" service at prices regulated at the cost-of-service. This wires service is considered a natural monopoly and the DPs have an obligation to service all customers in their area. The DPs adopt a very long-term perspective on serving their customers; the relationship between customers and DPs for this aspect of electric service has been largely unchanged for a century and is unlikely to change at any time in the future.

This long-term relationship is the basis for the natural advantages that come from transferring the capacity obligation to the DPs. With this shift in responsibility, the DPs can take a long term view toward contracting, because it knows it will have an ample supply of customers. This gives the DP substantial flexibility in arranging for capacity supply. It also eliminates the need for single-price capacity auctions.

INCREASED DP RESPONSIBILITIES

The DP responsibilities increase in one significant and substantial way. The DP will use bilateral, long term arrangements to procure capacity. These bilateral arrangements will be for capacity only, not capacity and energy, as the energy markets are not affected (directly) by this change. With captive customers, the DP is free to contract individually with each supplier, under terms that can be tailored for each situation. This flexibility is the key advantage of this approach.

The DP will manage a portfolio of capacity supply contracts which will likely contain a variety of contract structures. The DP will use this flexibility to drive down total costs by effectively managing the division of risks with each supplier. Thus, the builder of a new generator might contract for twenty years under terms that will be appealing to lenders, lowering the cost of construction and passing the savings on to customers. The generator on the verge of retirement, on the other hand, could have a special arrangement that looks year-by-year for renewal, where the generator gets the flexibility it needs to manage uncertain performance and the DP gets pricing that reflects the reduced reliability of the resource and the needs of the system. This flexibility would apply to load management supply options, as well. In congested areas, the DP can directly weigh the tradeoffs between generation, load, and transmission options for achieving reliable service and contract to meet those needs at the lowest cost. And in large market areas with robust supply and no congestion, the DP will manage a portfolio of contracts with varied durations to diversify risks and minimize the temporary price effects of shortages. All of these arrangements would be conducted under the existing oversight of state regulatory agencies, with input from the RRO, NERC and FERC oversight, as appropriate.

This is a significant change in responsibility for the DP. For some, the role will be welcomed. It will provide a way of addressing frustrations with the current market. Such things as relieving congestion problems through new generation, expanding load management programs, improving coordination of transmission and generation outages, and expanding certain renewable resources could all be addressed readily with the BiCap approach. For other DPs, the BiCap approach will require a level of market participation that exceeds current capabilities. The effort required to make this change is significant and tackling transition concerns will be important.

The DPs will pass the cost of capacity on to their customers. The incentive to lower costs, manage the portfolio effectively and negotiate competitive rates is largely the same as in the rest of the entities' business. DPs usually provide services at rate-regulated rates or are not-for-profit entities. Consideration could be given to providing additional incentives for effective management of capacity portfolios.

CHANGING THE ROLE OF THE RRO

The BiCap approach requires a change to the role of RRO that is deceptively simple. The RRO still determines capacity needs consistent with NERC standards. Those requirements are associated with peak load levels and have locational criteria when there are transmission constraints. Those overall requirements can be readily assigned to each DP on the basis of load. In congested areas the limited transmission capacity can be allocated on the basis of customer load, although other allocations could be made if appropriate. On a periodic basis, perhaps just before the seasonal peak, the RRO determines whether each DP has met its load obligations, by reviewing the sourcing arrangements and ensuring that the suppliers meet appropriate quality requirements. If DPs fail to contract for adequate capacity, the RRO will assess penalties. All of this is consistent with the reliability role that is central to the RRO's operations.

Beyond those activities, the RRO's role in the market for capacity is diminished greatly. There is no need for the RRO, or any other entity, to conduct capacity auctions for the system (although DPs could use auctions if desired). And there is no involvement of the RRO in setting capacity prices. That means there is no longer any requirement to do such things as develop capacity demand curves, set qualification standards for future generation capacity, evaluate buyer or seller market power (at least as currently conducted) or other such things.

SUPPLIERS FACE A DIFFERENT MARKET

Capacity can be supplied from generators or demand-side management, and for discussion purposes it is easiest to address them separately.

With respect to generators, first consider what does not change. Generators have to meet all the current technical requirements to qualify as capacity. They also continue to sell energy in the same manner as today. In selling capacity, however, rather than dealing with RRO-run auctions, they sell to DPs. Generators will be free to sell on short-term or long-term bases and to contract with one or more purchasers. Each contract will detail performance terms, generally associated with meeting the technical requirements of capacity in the region, and will address the financial consequences (between the DP and the generator) in cases where the generator fails to perform. The generator is not exposed to penalties directly from the RRO.

The BiCap approach is the same for demand-side capacity resources. As long as those resources are recognized as capacity by the RRO, the seller is similarly free to contract with DPs. For example, assume that the demand-side programs are sold and implemented through for-profit, competitive LSEs offering a service such as interruptible load. Those LSEs work with customers to create capacity credits that meet the RRO requirements, and then can sell them bilaterally to any DP. In other cases, the LSEs may want to offer a service that is not recognized as capacity by the RRO, but still reduces capacity requirements. An example might be certain energy efficiency improvements. As long as the local DP recognizes the program as reducing its need for capacity, the opportunity exists for the LSE to offer the service to customers and negotiate directly with the DP to capture some of the value created by the reduced capacity charges.

INCENTIVES ARE REQUIRED TO ENSURE COMPLIANCE

Capacity shortfalls will result in regulatory penalties; this is essential in any capacity market. This proposal is not dependent on a single approach for structuring penalties and incentives. One option would be to establish a penalty rate derived from the all-in cost of new capacity, such as 120% of the cost of a peaking combustion turbine facility on a levelized dollar/MW basis. This penalty suggestion is not net of expected energy revenues of that facility, and therefore is substantially more than would be expected to encourage new investment.[2]

The penalty is sufficient to create demand for adequate capacity. Capacity suppliers are not exposed directly to the penalty, but will work to meet the demand from the DPs. The financial incentives for capacity suppliers to have their facilities meet the system capacity requirements will be covered through the bilateral contracts.

Note: the determination of the cost of new entry has been highly controversial in some current markets. That is because this cost assumption has been a critical input to the development of demand curves that set the price for all capacity sales. Under BiCap, this penalty cost will be a very minor part of the entire market. Therefore, its determination is not expected to be as controversial as it is currently. Further, the penalty can be avoided completely by purchasing adequate supply.

MARKET POWER ISSUES ARE REDUCED, BUT NOT ELIMINATED

Today's capacity markets are rife with market power problems that are addressed through regulatory patches. While the rules vary by jurisdiction, there are artificial demand curves, bid caps, bid minimums, rules against withholding by suppliers, concerns about buyer-side market power, and more. It is hard to imagine a system that could be much worse. There is no evidence that the market price in any current capacity market is equal to the marginal cost of supplying the capacity for that period.[3]

In evaluating market power concerns under BiCap, it is helpful to work through a range of possible situations. For DPs in large RROs with workably competitive supply markets and without significant transmission congestion problems, there should not be sell-side market power problems. And since the DPs ultimately have to find suppliers, they have no ability to withhold demand. The bilateral nature of contracting, with different durations, different contract terms and with contracts signed at different times all contribute to the competitiveness of the market. The penalty mechanism provides a one-year cap on what a seller can charge, but even if tightness of supply raises the possibility of shortages, the potential for multi-year contracting provides a means for buyers and sellers to reach a negotiated price beneficial to both.

Market power concerns can get a bit trickier in load pockets, where DPs have limited alternatives for supply. One advantage of BiCap is the ability, over the long term, for the DP to weigh transmission and supply side options directly against each other. On the transmission-solution side, a DP can develop estimates and consider the timing (including long-term consequences) of a transmission upgrade. It can directly weigh that alternative against long-term contracts

2 The money collected from such penalties might be allocated to capacity supplies that meet the RRO requirements, but have not been sold. Thus, unassigned capacity in the market which actually helps the system maintain adequacy will receive compensation. As long as there is more capacity in the market than needed to meet requirements, the pro rata allocation of penalty collections will be less than the penalty amount on a $/MW basis. This will encourage bilateral contracting.

3 Even in cases where the price might be based on the bid of new entrants, that bid reflects a one-year price at which the supplier is willing to build a new capacity resource with a long lifetime. Even in cases where the first year price is extended for a few years, it does not cover the entire marginal cost of adding a resource (i.e., the construction cost).

for new supply, extending the life of existing resources or any other option. The flexibility in the duration of such contracts will be beneficial, as the DP can develop a plan for both long-term solutions and interim measures.

In some instances there are resources that are essential to maintaining reliable service in local areas and effectively have monopoly power. Market design alone, whether it is BiCap or traditional capacity markets, is inadequate to addressing such problems. In these situations, the approaches currently used to mitigate such market power can still be used, including reliability must-run contracts.

THE BENEFITS OF BICAP WILL BE DEMONSTRATED IN LOWER COSTS

This shift in obligation for capacity from competitive LSEs to regulated DP will strike some as a step away from competitive markets. But while LSEs may be unregulated entities, their role in current capacity markets is greatly diminished. The current structures are a far cry from what economists would consider an openly competitive market and we tolerate interventions with forced auctions, price caps, price floors and regulatory involvement at every step. Given this situation, the move to the BiCap approach is pro-competitive in that prices will be set by willing parties through a competitive process such as bilateral negotiation or private solicitation. The more important question, however, is which approach is most likely to be in the public interest? And most simply, which approach is likely to achieve the desired reliability levels at the lowest cost? BiCap is clearly the winner. By giving the regulated monopolist with captive customers (the DP) the obligation to obtain this service and the freedom to negotiate arrangements that better manage risk and maximize efficiency will lower costs.

The DP can conduct tradeoffs between generation and transmission for addressing congestion in ways that cannot be accomplished in a short-term capacity market context. The DP can also contract directly for the exact amount of capacity that is needed, rather than rely on supply curves to set varying prices and market-clearing quantities in a pseudo-market construct that inherently drives up costs. Not only will BiCap increase overall market efficiency, it will reduce risks to capacity suppliers, driving down their cost of capital. The re-allocation of costs and risks among market participants is not a zero-sum-game; it is a real reduction in risks that will directly translate into costs savings for consumers. It is time to create a market that works for the benefits of all participants.

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PJM's "Capacity Performance" Tariff Changes: Estimated Impact on the Cost of Capacity

prepared for the American Public Power Association
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This report provides an estimate of the cost impact of PJM's recent "Capacity Performance" ("CP") package of changes to its Reliability Pricing Model ("RPM") capacity construct. The CP rules impose new costs and risks onto capacity providers, leading many of them to offer capacity at higher prices, as PJM has acknowledged.[1] In addition, under the new CP rules, cost-based offer caps, which were in place as a market power mitigation measure, were eliminated, which also contributes to higher clearing prices.

This report estimates the impact of CP on capacity prices and capacity cost for the 2016/17, 2017/18 and 2018/19 delivery years; other potential cost impacts are also briefly discussed. This report does not describe the various changes associated with the Capacity Performance implementation, except as needed for the purposes of the cost estimate. More information on Capacity Performance is available from PJM's website, for instance at http://www.pjm.com/markets-and-operations/rpm.aspx.

Summary of Results

The additional market capacity cost due to the Capacity Performance rules is estimated at $7.3 billion over the coming three delivery years: $2.3 billion, $1.7 billion, and $3.3 billion for the 2016/17, 2017/18, and 2018/19 delivery years, respectively.

For the 2016/17 and 2017/18 delivery years, special "transition" auctions were recently held to acquire commitments to provide the Capacity Performance capacity product. All of the cost of the commitments resulting from these transition auctions, net of the cost of the extinguished prior RPM commitments, is considered a cost of the CP implementation. For the 2018/19 delivery year, an RPM base residual auction was recently held through which PJM acquired the new CP product to meet 80 percent of the reliability requirement, with the remainder satisfied with non-CP or "Base" resources. This report estimates that the auction, which cleared at $164.77/MW-day, would have cleared at $124.23/MW-day, "but for" CP. Based on this estimated clearing price, the total market capacity cost would have been $3.3 billion less than the $10.9 billion in market capacity cost that resulted from the auction.

The remainder of this report describes the approach and assumptions underlying these cost estimates.

Total Additional CP Capacity Cost For the 2016/17 and 2017/18 Delivery Years

Through two special "transition incremental" auctions held in August and September 2015, PJM acquired commitments to provide the Capacity Performance product to meet 60% and 70% of the reliability requirements for the 2016/17 and 2017/18 delivery years, respectively.[2] For cleared resources, the new commitments resulting from these auctions replace any prior commitments to provide RPM capacity. Thus, for each of these auctions, the total additional capacity cost is the total cost of the new CP commitments, minus the total cost of the extinguished prior RPM commitments. These calculations are shown in Tables 1 and 2. While the auctions established single clearing prices for the entire RTO, these calculations include zonal details as necessary to reflect the variation of the prior commitment prices by zone.

PJM had already acquired RPM commitments in excess of its reliability requirements for these two delivery years. The transition auctions further expanded the excess capacity, because some resources that cleared in the transition auctions

[1] PJM, 2018/19 Base Residual Auction Results, p. 29 ("With the transition to the Capacity Performance product, the implied costs of committing to be a Capacity Resource increases [sic] due to the need to make improvements in generator performance during Performance Assessment Hours. These increased costs could be related weatherization, improved maintenance, and costs for fuel assurance. This shifts the supply curve for resources up and leads to higher capacity market prices overall.") In addition to these costs, the risk of performance-related penalties will likely lead many capacity providers to include a risk premium in their capacity offers.

[2] A concise summary of the rules applicable to these auctions is available at http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2018-cp-transition-incremental-auctions-rules-schedule-planning-parameters.ashx.

had not previously cleared in RPM. While PJM's tariff calls for it to attempt to sell excess cleared capacity back to the market through incremental auctions under some circumstances, there is presently no provision in the tariff for selling back the excess resulting from these CP transition auctions. However, PJM has recently proposed tariff changes to allow such sales.[3] If the tariff changes are approved, the excess resulting from these auctions would be offered back in addition to excess resulting from further load forecast reductions, which, according to the most recent documents, are likely to be substantial.[4] If, in addition to excess capacity due to load forecast reductions, the additional excess capacity from the transition auctions is offered and clears, it is likely to clear at a very low price. Because the quantities, prices, and cost savings from any such sales are likely to be quite small, no estimate of the potential savings from such sales has been included.

Table 1: Additional Cost Resulting from the CP Implementation 2016/17 Delivery Year Transition Incremental Auction

	Rest of RTO excl. ATSI	ATSI	MAAC [1]	Total RTO
Transition Auction Results:				
Total cleared capacity (MW)	74,374.0	4,608.5	16,114.1	95,096.6
Converted commitments	73,350.5	2,133.1	15,367.2	90,850.8
New commitments	1,023.5	2,475.4	746.9	4,245.8
Clearing price ($/MW-day)	$134.00	$134.00	$134.00	
Cost/MW-day of prior Commitments [2]	$59.37	$114.23	$119.13	
Additional Cost per MW-day:				
Converted commitments [3]	$74.63	$19.77	$14.87	
New commitments	$134.00	$134.00	$134.00	
Auction Additional Cost ($ million/year):				
Converted commitments	$1,998.1	$15.4	$83.4	$2,096.9
New commitments	$50.1	$121.1	$36.5	$207.7
Total:	$2,048.1	$136.5	$119.9	**$2,304.5**

[1] PJM's report identified previously committed capacity in the PSEG zone that cleared in the transition auction, despite PSEG having cleared at a higher price in the base residual auction. However, PJM staff explained that this capacity is electrically connected at high voltage and earns the EMAAC price.

[2] The 2016/17 base residual auction clearing prices were used as the cost of prior commitments. For a small quantity of cleared resources, the price may have been established in a prior incremental auction.

[3] The additional cost is the difference between the auction clearing price and the price of the prior RPM commitment, assumed to be the base residual auction price.

Sources: PJM, 2016/17 Capacity Performance Transition Incremental Auction Results, Tables 1 and 2.

3 PJM Markets and Reliability Committee Meeting, October 1, 2015, Item 6.

4 PJM Markets and Reliability Committee Meeting, October 1, 2015, PJM presentation for Item 9, Load Forecast Update, slide 3 (showing further reductions in the forecast of over 4,000 MW for 2016 and 2017).

Total Additional CP Capacity Cost for the 2018/19 Delivery Year

To estimate the impact of the CP implementation on the 2018/19 base residual auction, it is necessary to estimate how the auction would have cleared, had the CP rules not been implemented. Specifically, the goal is to estimate the "But For" clearing prices and quantities that would have occurred had all the other changes to supply and demand taken place, but not the implementation of the CP rules.

The approach was to estimate what the 2018/19 capacity offer supply curve would have been, had CP not occurred, and then to clear this supply curve against the 2018/19 sloped capacity demand curve that was used in the auction. The 2018/19 "But For" supply curve was estimated as follows. First, the slope of the supply curve in the relevant price/quantity range was estimated, based on sensitivity analysis of the prior base residual auction; then the supply curve was shifted based on the actual change in total offered and cleared supply between

Table 2: Additional Cost Resulting from the CP Implementation 2017/18 Delivery Year Transition Incremental Auction

	Rest of RTO	MAAC [1]	Total RTO
Transition Auction Results:			
Total cleared capacity (MW)	73,726.0	38,468.5	112,194.5
Converted commitments	66,575.9	35,601.6	102,177.5
New commitments	7,150.1	2,866.9	10,017.0
Clearing price ($/MW-day)	$151.50	$151.50	
Cost/MW-day of prior Commitments [2]	$120.00	$120.00	
Additional Cost per MW-day:			
Converted commitments [3]	$31.50	$31.50	
New commitments	$151.50	$151.50	
Auction Additional Cost ($ million/year):			
Converted commitments	$765.5	$409.3	$1,174.8
New commitments	$395.4	$158.5	$553.9
Total:	$1,160.8	$567.9	**$1,728.7**

[1] PJM's report identified previously committed capacity in the PSEG zone that cleared in the transition auction, despite PSEG having cleared at a higher price in the base residual auction. However, PJM staff explained that this capacity is electrically connected at high voltage and earns the EMAAC price.

[2] The 2017/18 base residual auction clearing prices were used as the cost of prior commitments. For a small quantity of cleared resources, the price may have been established in a prior incremental auction.

[3] The additional cost is the difference between the auction clearing price and the price of the prior RPM commitment, assumed to be the base residual auction price.

Sources: PJM, 2017/18 Capacity Performance Transition Incremental Auction Results, Tables 1 and 2.

the 2017/18 and 2018/19 base residual auctions. The approach, which is described in further detail in an appendix, resulted in an estimated "But For" clearing price of $124.23/MW-day. The resulting "But For" cost estimate for the 2018/19 base residual auction is shown in Table 3.

Table 3: Estimated Additional Cost Resulting from the CP Implementation 2018/19 Delivery Year Base Residual Auction

	PEPCO	EMAAC	PPL	COMED	Rest of RTO	Rest of SWMAAC	Total
Base Residual Auction Results (actual results):							
Total cleared quantity (MW)	5,478.7	31,069.0	9,526.9	23,320.4	91,739.9	5,702.0	166,836.9
Cleared CP resources	4,875.7	22,970.6	8,380.4	20,564.4	79,264.5	4,544.8	140,600.4
Cleared Base generation	103.0	6,573.5	663.7	891.5	7,475.6	569.8	16,277.1
Cleared Base DR/EE [1]	500.0	1,524.9	482.8	1,864.5	4,999.8	587.4	9,959.4
Clearing price – CP ($/MW-day)	$164.77	$225.42	$164.77	$215.00	$164.77	$164.77	
Clearing price - Base generation	$149.98	$210.63	$75.00	$200.21	$149.98	$149.98	
Clearing price – Base DR/EE	$41.09	$210.63	$75.00	$200.21	$149.98	$59.95	
Base Residual Auction Total Capacity Cost (actual cost; $ million):							
CP resources	$293.2	$1,890.0	$504.0	$1,613.8	$4,767.1	$273.3	$9,341.4
Base generation resources	$5.6	$505.4	$18.2	$65.1	$409.2	$31.2	$1,034.8
Base DR/EE resources	$7.5	$117.2	$13.2	$136.3	$273.7	$12.9	$560.8
RPM cost - total	$306.4	$2,512.6	$535.4	$1,815.2	$5,450.0	$317.4	$10,936.9
"But For" CP Estimated Clearing Quantities, Prices and Cost: [2]							
Total cleared quantity (MW)							168,309.6
Clearing price ($/MW-day)							$124.23
RPM "But For" cost - total							**$7,631.9**
Estimated Increase in Capacity Cost due to CP, 2018/19 Base Residual Auction:							**$3,305.0**

[1] Base DR/EE = Demand Resources and Energy Efficiency offered as Base resources.

[2] The determination of the "But For" quantities and prices is documented in the appendix to the report. All resources were assumed to earn the full clearing price (with no zonal prices or discounts for subannual resources).

Sources: PJM, 2018/19 Base Residual Auction Results, Tables 3B and 4, and the accompanying spreadsheet.

A few additional assumptions were adopted for the cost estimate:

1. The Eastern MAAC and ComEd zones cleared at prices higher than the RTO region in the 2018/19 base residual auction. It is assumed that but for the CP rules, these regions, neither of which had separate prices in the 2017/18 base residual auction, would have cleared with the rest of the RTO at $124.23/MW-day.
2. Without the CP implementation, presumably the Annual and Sub-annual (mainly Extended Summer and Limited demand response) resource categories would have again been used in the auction, potentially resulting in a price discount for a subset of cleared resources. However, for this cost estimate, it was assumed that all resources clear at a single clearing price. This assumption will tend to overstate the likely "But For" cost somewhat, and thereby understate the cost resulting from the CP implementation.

Increase in Capacity Cost Due to CP Beyond 2018/19

The next base residual auction, for the 2019/20 delivery year, would again allow the Base capacity resources to participate, but the quantity would be reduced to a maximum of 10% of the reliability requirement (compared to 20% for 2018/19). The additional cost due to CP for that delivery year might be higher than the estimated additional cost for 2018/19, due to the further reduction in Base product. For the following delivery year, 2020/2021, the Base product is to be eliminated and the entire reliability requirement satisfied with CP resources, which could potentially result in another large increase in the clearing prices and costs due to CP. Estimates of the potential impacts of CP beyond 2018/19 have not been prepared.

Potential Impact of CP on Other Types of Costs

While the goal of the new CP rules is to encourage improved generator performance, these rules could potentially have impacts on other types of costs. In particular, the CP rules could have impacts on energy costs and on customer outage costs. These potential impacts are briefly discussed in this section.

With respect to energy costs, improved generator performance certainly would have resulted in much lower energy costs during the "polar vortex" period of extreme cold in early 2014, when very high forced outage rates caused price spikes in the PJM energy markets. However, that very extreme period followed nineteen winters during which such extreme cold did not occur, capacity was never scarce during winter, and winter energy prices remained low in PJM. The polar vortex period revealed accumulated fuel and winterization issues at many plants. Apparently, many of these issues were resolved by the winter of 2015, when performance was much improved.[5] The improved performance in winter 2015 reflects numerous steps taken by market participants and PJM following the polar vortex events, and well before Capacity Performance was approved or implemented.

Looking forward, extreme cold such as occurred during the polar vortex period is quite rare, PJM has substantial excess capacity already committed through May 31, 2019, and generator performance was much improved even before CP, so it is unclear that CP is likely to have a substantial incremental impact on future energy prices. The expected value of the incremental impact of CP on future annual energy prices is likely an order of magnitude lower than the estimated impact on capacity cost developed in this report.

With respect to the potential impact of CP on customer outage cost, this too is likely to be very low for the same reasons. Even during the polar vortex period no load was dropped. With the improved generator performance that occurred before CP, and PJM's excess capacity, the likelihood of load loss is very low, and the amount by which CP might further reduce this load loss is extremely low. Even assigning a quite high "Value of Lost Load", the expected value incremental impact of CP on customer outage cost is likely an order of magnitude less than the capacity cost impact.

5 PJM, 2015 Winter Report, May 13, 2015 (noting that "[g]enerator performance in February 2015 showed improvement ", and that "[f]or the morning of Feb. 20, 2015, when PJM reached a new all-time winter peak, the forced outage rate was 13.4 percent" compared to 22 percent during the Jan. 7, 2014 peak; p. 5).

Appendix: Methodology for Estimating the 2018/19 Base Residual Auction Clearing Quantity and Price "But For" Capacity Performance

This section explains in further detail how the "But For" CP 2018/19 base residual auction clearing quantity and price ($124.23/MW-day) were estimated.

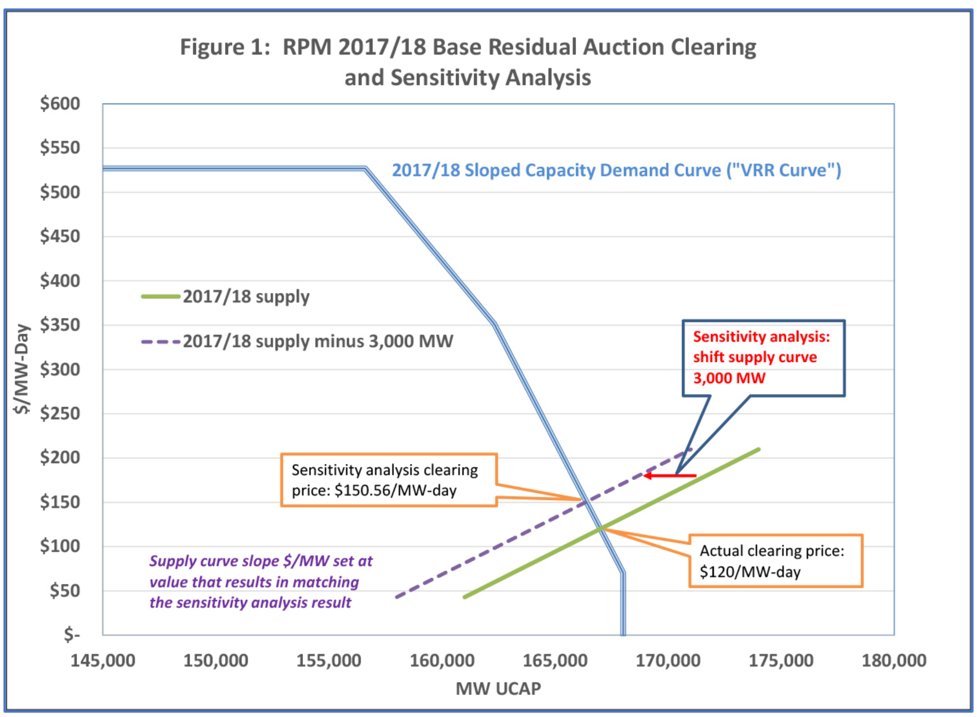
The first step was to estimate what the 2018/19 base residual auction capacity supply curve would have been without the CP rules. The actual auction supply curves are not published due to concerns that such information could facilitate anti-competitive conduct.[6] However, PJM has published sensitivity analyses for the 2017/18 base residual auction that are useful for this purpose (sensitivity analyses for the 2018/19 auction will also be performed, but likely will not be available for months).

In particular, PJM performed a sensitivity analysis in which 3,000 MW of supply was removed from the RTO supply curve, and the resulting clearing price and quantity were reported.[7] The clearing price for the RTO region rose from $120/MW-day to $150.56/MW-day under this scenario. A supply curve with a slope of $12.8/1,000 MW is consistent with this result – that is, if such a supply curve clears at $120/MW-day and is then shifted 3,000 MW, the resulting clearing price is as identified in the scenario analysis. This analysis is illustrated in Figure 1.

The capacity supply curves are typically not linear but rise at an increasing rate, especially at high price levels. However, PJM's sensitivity analysis, and the analysis documented here, use only a relatively small segment of the supply curve, over which the quantity ranges by 3,000 MW or less (less than two percent of the entire supply curve offered quantity), so it is reasonable to assume the supply curve is approximately linear within this short segment. In any case, the results are not very sensitive to this assumption.

The next step was to estimate how the supply curve shifted between the base residual auctions for 2017/18 and 2018/19 as indicated by changes in the quantity of capacity offered. PJM reports that for 2018/19, the total supply offered increased by 1,052.7 MW.[8] However, some of this net incremental supply may have been relatively high cost, so the quantity was reduced by the fraction of offered supply that cleared in the auction, resulting in the assumption that the supply curve shifted by 976 MW. This shift amounts to about one half of one percent of the 178,838.5 MW offered into the 2017/18 base residual auction. This small shift would tend to lower the auction clearing price.

The sloped capacity demand curve (aka Variable Resource



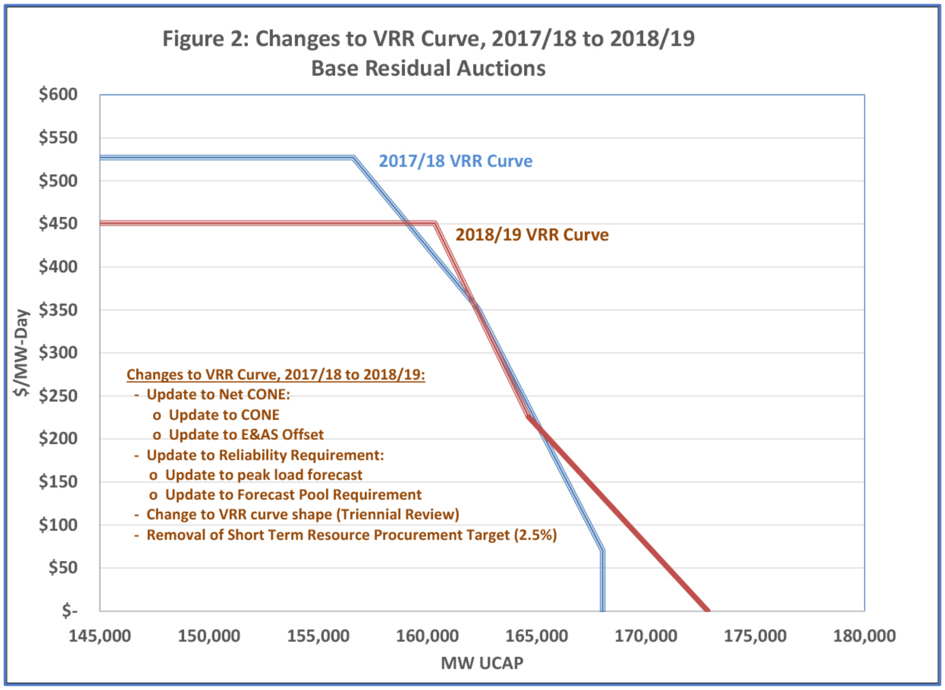
[6] PJM and the PJM market monitor publish illustrations of supply curves that do not reveal the shape or slope of the actual supply curves. The sensitivity analyses, which are performed using the actual supply curves, reveal the actual slopes of the supply curves over specific ranges.

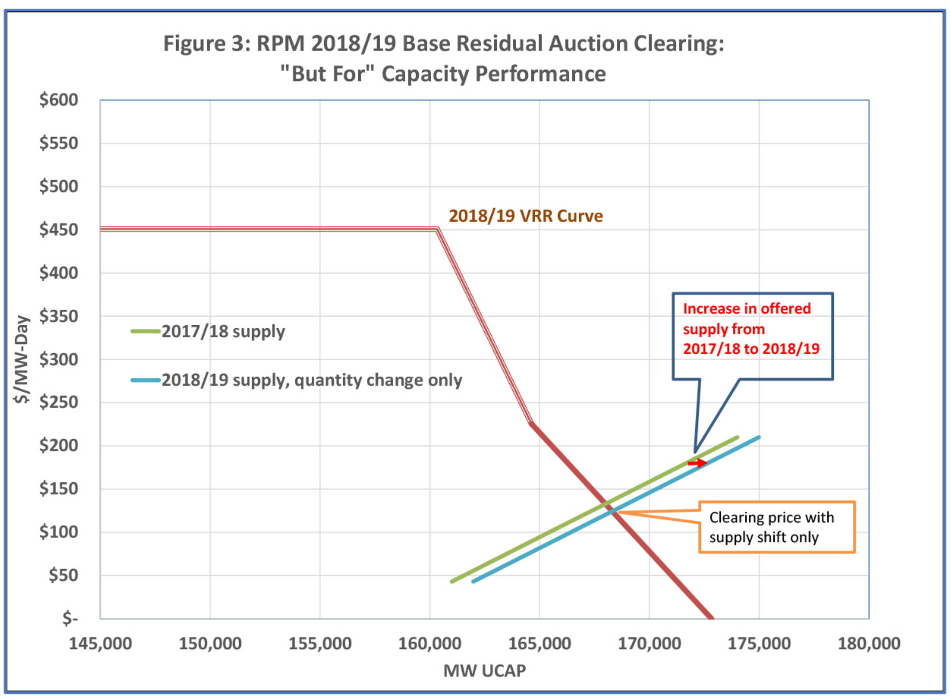
[7] PJM, Scenario Analysis for the 2017/18 Base Residual Auction, scenario 2, available at http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-bra-scenario-analysis.ashx.

[8] PJM, 2018/19 Base Residual Auction Results, Table 6 p. 20.

Requirement, or "VRR" curve) also changed for the 2018/19 base residual auction, due to updates to the Net CONE price parameter; updates to the Reliability Requirement quantity parameter; changes to the shape of the curve; and the removal of the Short Term Resource Procurement Target (aka 2.5% holdback). The 2017/18 and 2018/19 VRR curves are both shown in Figure 2. In the relevant price range, the 2018/19 VRR curve is shifted to the right, which would tend to raise prices.

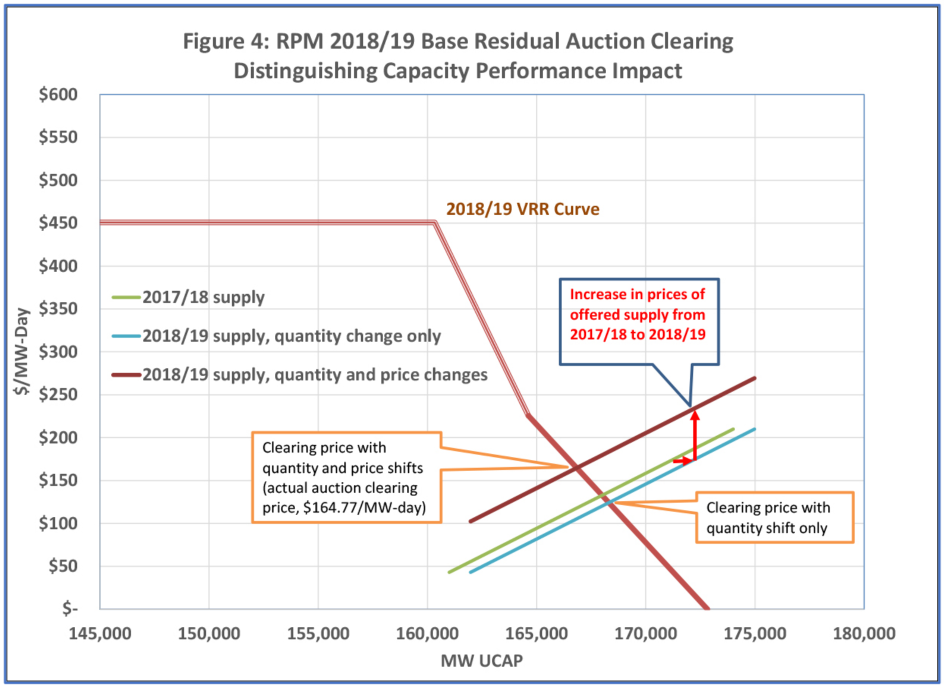
The next step was to find where the estimated 2018/19 supply curve (with slope as determined using the sensitivity analysis, and shifted based on the slight increase in offered supply) would clear against the actual 2018/19 VRR curve. This step is shown in Figure 3. The resulting clearing price is $124.23/MW-day. That is, based on the changes in offered supply and in the VRR curve, the 2018/19 base residual auction would have been expected to clear a small amount higher than the $120/MW-day

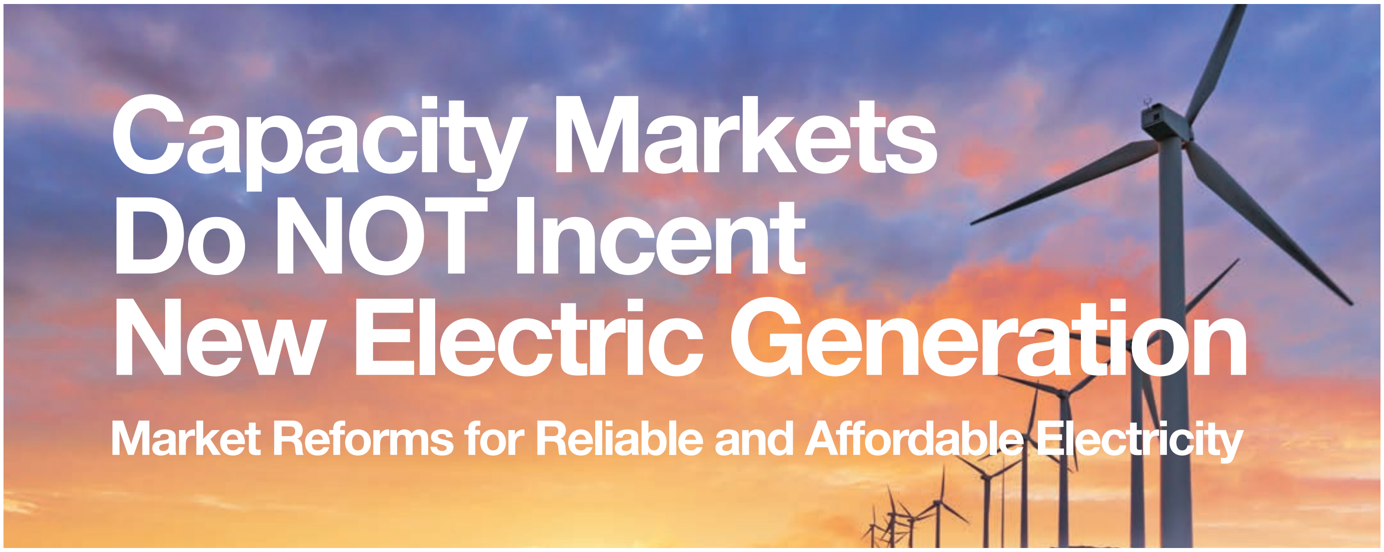




price from the 2017/18 auction. The actual auction clearing price was considerably higher ($164.77/MW-day, or $40.54/MW-day higher), presumably due to CP.

The estimated "But For" 2018/19 supply curve described above, if shifted upward by $59.50/MW-day, results in the actual auction clearing price of $164.77/MW-day. This is illustrated in Figure 4. Thus, according to the assumptions used for this cost estimate, the CP rules caused the supply curve offer prices to rise in the relevant price range by $59.50/MW-day.





Capacity Markets Do NOT Incent New Electric Generation

Market Reforms for Reliable and Affordable Electricity

APPA® American Public Power Association

SEVENTY-FIVE YEARS

Capacity Markets Do NOT Incent New Electric Generation

2015 Update

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American Public Power Association
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American Public Power Association
Seventy-Five Years

Introduction and Summary of Findings

This paper from the American Public Power Association (APPA) analyzes data on new electric generation capacity in the U.S. that began operating in 2014, and the financial arrangements behind such capacity.

The analysis revealed that almost all the new capacity was constructed under a long-term wholesale power contract, or utility ownership, or a financial hedge guaranteeing a minimum price. Just 4.8 percent of the new capacity was built only for sale into a market — this includes new facilities for which no information could be found about the financial arrangements.

In 2014, 14 percent of new capacity was built within the footprint of the Regional Transmission Organizations (RTOs) with mandatory capacity markets (PJM Interconnection, ISO New England and parts of the NY ISO), but these RTOs cover almost a quarter of the megawatt-hours consumed in that year.[1] In addition, over half of the capacity built in the mandatory markets was a single plant constructed by a vertically integrated investor-owned utility.

Prior analyses of such data were conducted for new capacity that began operating in 2011 and 2013.[2] There have been several developments since the last APPA study was released in October 2014:

- PJM Interconnection (PJM) and ISO New England (ISO NE) have held capacity auctions under new rules with performance-based penalties and incentives and that were accompanied by significant price increases.
- The U.S. Environmental Protection Agency has issued its Clean Power Plan to limit emissions of carbon dioxide from electric generating units.
- Additional nuclear plant closures have been announced in RTO regions.
- The Supreme Court has agreed to review the decision of the U.S. Court of Appeals for the Fourth Circuit upholding the federal district court's invalidation of the Maryland Public Service Commission's order requiring the state's investor-owned distribution utilities to sign long-term "contracts for differences" providing a fixed revenue stream to the developer of a new natural gas power plant.

These developments have factored into the ongoing debate about whether the capacity markets operated by the RTOs — especially the mandatory capacity markets in ISO NE and PJM, as well as parts of the New York ISO (NY ISO) — are an effective means to provide a reliable supply of resources while addressing environmental, reliability, and other policy goals.

The Federal Energy Regulatory Commission (FERC) and the RTOs appear to prefer to continue to tweak these markets rather than consider new paradigms for resource development. For example, when over 20 percent of the capacity clearing PJM's capacity auctions was unavailable to perform during the extreme cold in the winter of early 2014, PJM imposed new capacity performance rules without any demonstration of benefits to justify the billions of dollars of additional costs.[3] APPA has instead long proposed that the mandatory capacity markets be phased out and replaced by residual, voluntary markets with bilateral contracting and ownership as the central means for ensuring resource adequacy.

The data in this analysis show that simply because a new generator is constructed in an RTO with a capacity market, that does not indicate that the market was the principal reason for the decision to construct that new generation in that location.

Moreover, there are significant differences between RTOs with mandatory capacity markets and those that do not have such markets and whose utilities generally own or contract for resources to serve their load, including the Midcontinent Independent System Operator (MISO), the California Independent System Operator (CA ISO) and the Southwest Power Pool (SPP). (See Appendix B for a more detailed description of the capacity markets.)

1 These figures are based on U.S. Energy Information Administration data on state-level retail electricity sales. Only states for which the majority of the state was within an RTO were assigned to that RTO. No new capacity was built in Illinois, which is split between RTOs.

2 *Power Plants are Not Built on Spec, 2014 Update,* American Public Power Association, October 2014, http://www.publicpower.org/files/PDFs/Power_Plants_Not_Built_on_Spec_2014.pdf

3 For an analysis of the costs of PJM's new capacity performance rules, see *PJM's 'Capacity Performance' Tariff Changes: Estimated Impact on the Cost of Capacity,* by James F. Wilson of Wilson Energy Economics, http://appanet.files.cms-plus.com/PDFs/PJM_Capacity_Performance_Wilson_10_8_15.pdf

Analysis of New Generation Constructed in 2014

There were three primary sources of funding for the new electric generation capacity built in 2014, as summarized in Table 1 — utility ownership (42 percent of the capacity in MW), purchased power agreements (PPAs) for the sale of the power to a utility (30 percent), or a PPA or other hedge contract with a financial entity (18 percent).

Just 4.8 percent of the new generation capacity was built solely for sale into RTO markets, almost all of which was from one plant — the 738 MW West Deptford combined-cycle plant in New Jersey.

Natural gas accounted for half of the new capacity built, and a little over three-fourths of the capacity built under utility ownership. Solar and wind accounted for 19 and 27 percent of the new capacity, respectively. Natural gas builds were characterized by a smaller number of larger projects, while the solar installations consisted of a larger number of smaller projects with almost all built under utility or individual customer PPAs. Wind capacity covered a range of differently sized projects, and a mix of financing arrangements.

Table 2 shows the same categories of generation distributed by the number of projects. In this case, the PPAs with utilities accounted for a higher portion (54 percent) and ownership by utilities a lower portion (14 percent) than when viewed by MWs, indicating that larger capacity projects tend to be built under utility ownership. The number of projects built for market sales accounts for 3 percent of all projects.

Table 3 shows the distribution of new capacity constructed within the RTO footprints revealing that 76 percent of the new capacity was constructed within an RTO region, with a disproportionate share in the CA ISO and the Electric Reliability Council of Texas (ERCOT). These two RTOs accounted for 40 percent of the new capacity, while California and Texas consumed17 percent of the megawatt- hours in 2014. Two primary drivers in these states are investor-owned utility contracts for solar power in California and new wind projects built in the Competitive Renewable Energy Zone in Texas, a $7 billion construction project of almost 3,600 circuit-miles of transmission.[4]

The new capacity built in the three Eastern RTOs with mandatory capacity markets (PJM, ISO NE, and NYISO[5]) represents just 14 percent of the total, yet these states accounted for almost one-fourth of all electricity consumption and the capacity needs in these RTOs may be greater than in other regions because of the significant coal and nuclear plant retirements.[6]

Over half of the capacity in the Eastern RTOs was constructed under utility ownership, almost all of which is accounted for by Dominion Power's Warren natural gas plant. This plant was constructed by a vertically-integrated utility and cleared PJM's capacity auction under an exemption to the "minimum offer price rule."[7] In the absence of this single plant, the Eastern RTO share drops to 6.6 percent.

Table 4 shows the distribution of the three-fourths of new capacity that is supported by utility PPAs and utility ownership according to type of utility. Public power utilities were responsible for 16 percent of the new MW built under utility contracts and 11 percent under ownership, both close to the public power share of sales of electricity (15 percent).[8] Public power represented large proportions of hydropower, landfill gas, and geothermal.

4 *2014 Wind Technologies Market Report,* US Department of Energy, http://energy.gov/eere/wind/downloads/2014-wind-technologies-market-report.

5 Although only the New York City and Lower Hudson Valley zones have the features of mandatory capacity markets, all of the capacity within New York State is included in this measure, resulting in an overestimate of the amount of capacity constructed in the mandatory capacity markets.

6 In PJM, almost 21 gigawatts (GW) of coal-fired capacity has retired since 2011 or plans to retire, including 7.5 GW for 2015, see Table 12-6, 2015 *Quarterly State of the Market Report for PJM: January through June,* http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015/2015q2-som-pjm-sec12.pdf; ISO New England reported in its *2015 Regional System Plan* that over 4,000 MW of resources will retire by the summer of 2018 (Section 5.3), http://www.iso-ne.com/static-assets/documents/2015/11/rsp15_final_110515.docx; and the NY ISO is facing the closure of two nuclear units: the 838 MW James A. FitzPatrick plant (http://www.entergynewsroom.com/latest-news/entergy-close-pilgrim-nuclear-power-station-massachusetts-no-later-than-june2019/) and the likely retirement of the 583 MW Ginna plant following the conclusion of the Reliability Support Services Agreement in 2017, see *Affidavit of Jeanne M. Jones on behalf of R.E. Ginna Nuclear Power Plant, LLC,* Federal Energy Regulatory Commission, Docket ER15-1407-000, http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14020270.

7 See Appendix B. The minimum offer price rule (MOPR) establishes a price floor for bids submitted by new capacity, making it more difficult for such resources to clear the auction. A number of parties in PJM negotiated MOPR exemptions for competitive entry and self-supply in 2012.

8 *US Electric Utility Industry Statistics,* American Public Power Association, http://www.publicpower.org/files/PDFs/USElectricUtilityIndustryStatistics.pdf

Table 1. Financial Arrangements for New Capacity in 2014 by Megawatts

Type of Arrangement	Generating Technolog												
	Biomass/ Biogas	Coal	Fuel	Geo-thermal	Hydro-power	Land-fill Gas	Natural Gas	Oil	Solar	Wind	Other**	Total	% of Total
Contracts	Megawatts of Capacity												
Contract with Utility				30.0	15.2	92.5			3,144.3	1,906.9	0	**5,233.9**	29.7%
PPA or Hedge with Financial Entity							1,516.0			1,596.7	0	**3,112.7**	17.6%
Other Contracts*							260.0			108.8	0	**368.8**	2.1%
Contract with Customer	60.0		1.4				260.0	10.1	122.7	25.3	0	**479.5**	2.7%
Subtotal Contracts	**60.0**		**1.4**	**30.0**	**15.2**	**92.5**	**2,081.0**	**10.1**	**3,267.0**	**3,637.7**	**0**	**9,194.8**	**52.1%**
Ownership													
Utility Ownership	50.0	99.0			132.3	9.6	5,972.3	14.8	70.4	1,001.4	81.0	**7,430.8**	42.1%
Customer Ownership	72.7		3.6	1.8		2.4	20.5	14.0	29.5	8.0	20.2	**172.7**	1.0%
Subtotal Ownership	122.7	99.0	3.6	1.8	132.3	12.0	5,992.8	28.8	99.9	1,009.4	101.2	**7,603.5**	43.1%
Market Sales							738.0		50.4	47.5	4.0	**839.9**	4.8%
Total	**182.7**	**99.0**	**5.0**	**31.8**	**147.5**	**104.5**	**8,811.8**	**38.9**	**3,417.3**	**4,694.6**	**105.2**	**17,638.2**	100.0%
% of Total	**1.0%**	**0.6%**	**0.0%**	**0.2%**	**0.8%**	**0.6%**	**50.0%**	**0.2%**	**19.4%**	**26.6%**	**0.6%**	**100.0%**	

*Other Contracts includes contracts for Renewable Energy Credits or for the sale of steam.

"**Other includes nuclear, storage and cogeneration. The nuclear MW is the upgrade of Xcel's Monticello nuclear power plant."

Note: The capacity of the projects covered in this paper amounts to 17,638 megawatts (MW), which is about 600 MW greater than the total amount of capacity provided by the U.S. EIA data. This additional amount is due to information on projects from other sources of data, such as the AWEA market report. FERC's infrastructure report for December 2014, reports a total of only 15,384 MW of new generation for 2014, partially due to some projects completed in 2014 that were in the January 2015 infrastructure report.

Table 2. Financial Arrangements for New Capacity in 2014 by Number of Projects

Type of Arrangement	Generating Technology												
	Biomass/ Biogas	Coal	Fuel Cell	Geo-thermal	Hydro-power	Land-fill Gas	Natural Gas	Oil	Solar	Wind	Other**	Total	% of Total
Contracts	Number of Projects												
Contract with Utility				1	2	12	1		143	19	0	**178**	53.6%
PPA or Hedge with Financial Entity							2			10	0	**12**	3.6%
Other Contracts*							1			2	0	**3**	0.9%
Contract with Customer	1		1				1	2	36	8	0	**49**	14.8%
Subtotal Contracts	**1**	**0**	**1**	**1**	**2**	**12**	**5**	**2**	**179**	**39**	**0**	**242**	**72.9%**
Ownership													
Utility Ownership	1	1			3	2	16	5	8	6	3	**45**	13.6%
Customer Ownership	6		3	1		1	4	1	12	3	4	**35**	10.5%
Total Ownership	**7**	**1**	**3**	**1**	**3**	**3**	**20**	**6**	**20**	**9**	**7**	**80**	**24.1%**
Market Sales							**1**		**6**	**2**	**1**	**10**	**3.1%**
Total	**8**	**1**	**4**	**2**	**5**	**15**	**26**	**8**	**205**	**50**	**8**	**332**	**100.0%**

*Other Contracts includes contracts for Renewable Energy Credits or for the sale of steam.

"**Other includes nuclear, storage and cogeneration. The nuclear MW is the upgrade of Xcel's Monticello nuclear power plant."

Table 3. Distribution of New Capacity Constructed in 2014 by RTO Footprint

	Contracts			Ownership		Market Sales	Total
	Utility	Financial	Other	Utility	Customer		
	Megawatts of Capacity						
Total MW	5,233.9	3,112.7	848.3	7,430.8	172.7	839.9	17,638.2
RTO Regions	3,843.7	3,112.7	838.3	4,686.0	91.0	839.9	13,411.5
% of Total	73.4%	100.0%	98.8%	63.1%	52.7%	100.0%	76.0%
Eastern RTOs*	15.0	8.9	276.0	1,348.9	30.8	814.4	2,494.0
% of Total	0.3%	0.3%	32.5%	18.2%	17.8%	97.0%	14.1%

*Eastern RTOs = PJM, NY ISO, ISO NE"

Table 4. Distribution of New Capacity (MW) Under Utility Ownership or Contracts

Total Utility Ownership or Contracts	Investor-Owned Utility	Public Power	Rural Electric Cooperative	Total
Biomass/Biogas	0.0	0.0	50.0	50.0
Coal	0.0	0.0	99.0	99.0
Fuel Cell	0.0	0.0	0.0	0.0
Geothermal	0.0	30.0	0.0	30.0
Hydropower	8.0	136.2	3.3	147.5
Landfill Gas	68.8	28.5	4.8	102.1
Natural Gas	5,106.4	666.9	244.0	6,017.3
Oil	0.0	12.0	2.8	14.8
Solar[1]	2,763.0	433.5	13.5	3,214.7
Wind	2,264.6	358.9	284.8	2,908.3
Other[2]	81.0	0.0	0.0	81.0
Total	**10,291.8**	**1,666.0**	**702.2**	**12,664.7**
Share of Total	**81%**	**13%**	**6%**	**100%**

1 Solar includes 4.7 megawatts under contract to all utilities, via the Vermont Electric Power Producers.

2 Other includes nuclear, storage and cogeneration. The nuclear MW is the upgrade of Xcel's Monticello nuclear power plant.

Financial Hedges

In 2014, an increased share of capacity was financed by "quasi-merchant" arrangements where a utility or end-use customer is not purchasing the power, yet the developer or an entity financing the project receives a guaranteed price for a period of time and for at least a portion of the megawatt-hours sold. A financial entity would provide this hedge as a purely financial product (such as a financial swap) that guarantees a minimum price. Such arrangements can structured as revenue puts, where the hedge provider sells an option to the developer for the sale of the power at a minimum guaranteed price.[9]

Another arrangement is a synthetic PPA[10], where the hedging party provides a steady stream of revenue based on a benchmark price, similar to a PPA, but does not purchase the power. If the market price exceeds the benchmark, the hedging party earns the difference. Hedging parties may play a role in financing the project or be an unrelated third party. A number of the wind projects built in 2014, primarily in Texas, have some type of financial hedge, commonly for a 10 to 12 year period.[11]

9 "Hedging Strategies for Power Contracts – Part Two: Revenue Put Options," *Energy Finance Report,* August 27, 2014, http://www.energyfinancereport.com/2014/08/hedges2/

10 "Hedging Strategies for Power Contracts – Part Three: Synthetic PPAs," *Energy Finance Report,* September 5, 2014, http://www.energy-financereport.com/2014/09/hedging-strategies-for-power-contracts-part-three-synthetic-ppas/

11 U.S. DOE, *2014 Wind Technologies Market Report,* http://energy.gov/eere/wind/downloads/2014-wind-technologies-market-report

In addition to the wind projects, two natural gas plants in Texas, Sherman and Temple I, both 758 MW projects developed by Panda Power Funds, utilized revenue puts. Because Panda Power could not secure long-term PPAs, the company sought mechanisms to provide sufficient revenue certainty to finance the plants. Panda was able to arrange four-year revenue put options with one of the equity investors in the project — the 3M Retirement Income Plan. Because of the relatively short-term revenue guarantee, the projects still required equity and Term Loan B financing,[12] rather than traditional debt, resulting in a higher cost of capital.[13]

Revenue put options and synthetic PPAs more closely resemble PPAs than they do merchant projects because they represent a means to avoid the volatility of market prices. In these cases, the developer is seeking the revenue certainty often viewed as a necessity for arranging the financing of new power plants.

12 Term Loan B debt is a higher-yield debt typically arranged between a corporate borrower and an institutional investor. These loans have less lender protection (or "covenants") than traditional debt. See for example: *Energy law insight: twist in the tale of the Term B loan,* August 9, 2013, http://www.windpowerengineering.com/featured/business-news-projects/energy-law-insight-twist-in-the-tale-of-the-term-b-loan/; *Announcement: Moody's: US power project loans becoming covenant-lite,* May 8, 2013, https://www.moodys.com/research/Moodys-US-power-project-loans-becoming-covenant-lite--PR_272684.

13 "North American Merchant Power Deal of the Year 2012, Sherman and Temple: Panda Returns," *Project Finance,* March 1, 2013, http://newsroom.pandafunds.com/news/north-american-merchant-power-deal-year-2012-sherman-and-temple-panda-returns

New Merchant Power

Although only a relatively small amount of pure merchant capacity has been built in the RTO regions to date, a significant amount of capacity from new merchant power plants has cleared the last three PJM capacity market auctions, known as Base Residual Auctions (BRAs). But the extent to which this capacity will actually be built is still uncertain.

In the BRAs held in 2013, 2014 and 2015, procuring capacity for the time period from June 2016 through May 2019, a total of 3,481 MW, 4,230 MW and 3,518 MW, respectively, cleared each auction under the "competitive entry" exemption from PJM's minimum offer price rule.[14]

To obtain this exemption, "a merchant plant developer can attest that it is receiving no anomalous revenue streams or subsidies that were not otherwise available to all market participants from state agencies or state procurement

14 Data are from the 2016/17, 2017/18 and 2018/19 *RPM Base Residual Auction Reports,* PJM Interconnection, http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx

processes that had not been deemed competitive and non-discriminatory." In other words, the plant cannot be receiving revenues from a long-term contract approved in a state proceeding, if such contract were only available to new plants or a specific technology, such as a combined-cycle plant.

For generation owned or contracted for by a utility, a specifically defined self-supply exemption is available. As a result, generation receiving the competitive entry exemption is built for direct sale into the PJM markets, and not under a long-term contract or utility ownership.

As PJM does not reveal the financial arrangements behind new generation, prior to the creation of the competitive entry exemption in the 2013 BRA, it was not known whether new generation was purely merchant or built under a long-term contract or ownership. For example, in the 2012 BRA, almost 5,000 MW of new generation cleared the auction, but APPA research found that at least two-thirds of this generation was built under ownership or long-term contracts.[15]

The roughly 11,000 MW of merchant generation that cleared the last three capacity auctions in PJM appears to indicate a change in the pattern reported in this study. But to date, just one purely merchant plant has been built in the PJM footprint — the West Deptford plant in New Jersey. (Exelon also completed the Fourmile wind project in 2014, and its Perryman 6 natural gas generating unit came on line in 2015, but both projects were built in compliance with the agreement for Maryland's approval of the Constellation-Exelon merger.[16])

Several large merchant power projects in the PJM region, likely to have been among those clearing the capacity auctions, have been delayed. For example, the Pennsylvania Department of Environmental Protection (DEP) announced last August that it had granted an extension of the air permit for Hickory Run, a planned 900 MW combined-cycle plant. The plant's developer, an LS Power affiliate, sent a letter to the DEP requesting the extension because "a slower than anticipated recovery in the local PJM Interconnection electrical markets resulted in the facility being unable to finance the project and commence construction prior to October 23, 2014."[17]

Tenaska has been delaying the planned start of construction of the Westmoreland 930 MW combined-cycle plant repeatedly from 2011 through late 2015 because of continued efforts to find long-term power purchase commitments, and the company's Lebanon Valley 950 MW project has also been delayed since 2009.[18]

In recognition of such uncertainties involving merchant plants, the consulting company, ICF International, stated that they assume in their internal forecasts that not all of the plants clearing the PJM capacity auctions will be built.[19]

The new merchant natural gas generation is typically financed by a combination of equity and Term Loan B financing, both of which require higher returns than traditional debt and are riskier investments. For example, Competitive Power Ventures, an independent power producer, estimates that a traditional debt financing with a 75/25 debt-to-equity ratio can cost over 20 percent less than a "merchant" project financing with a 50/50 debt-to-equity ratio.[20]

If a mandatory capacity market leads to a larger proportion of merchant plants clearing the auction, it is important for FERC and other policymakers to consider whether this trend is a beneficial model for energy resource planning. The uncertainty about whether and when the plants will be built makes it difficult to adequately plan for future reliability requirements. Moreover, should these projects be built, it is not clear if their impacts on fuel diversity, natural gas pipeline capacity and natural gas prices have been taken into account. Finally, the higher cost of capital also represents a significant drawback to relying on merchant capacity.

15 "PJM auction shows flaws in capacity market construct, critics say," Public Power Daily, June 4, 2012, http://www.publicpower.org/Media/daily/ArticleDetail.cfm?ItemNumber=35024

16 *Exelon Generation's New Maryland Natural Gas Plant Now Operational,* June 29, 2015, http://www.exeloncorp.com/Newsroom/pages/pr20150629_NewMDNaturalGasPowerPlantNowOperational.aspx

17 *Construction delayed on 900 MW Pennsylvania gas plant,* Electric Light and Power, August 11, 2014, http://www.elp.com/articles/2014/08/construction-delayed-on-900-mw-pennsylvania-gas-plant.html

18 *Tenaska natural gas-fueled power plant's foes air concerns to Westmoreland commissioners,* Pittsburgh Tribune-Review, January 9, 2015, http://triblive.com/news/westmoreland/7522829-74/plant-tenaska-power#ixzz3qg9cS1Iq. According to Tenaska, they are still "evaluating a site" for the Lebanon Valley Generating Station, as has been stated since 2009: http://www.tenaskalebanonproject.com/project-details/

19 *The Brutally Cold Truth about the Polar Vortex,* ICF International, April 29, 2014, http://www.icfi.com/insights/webinars/2014/recording-polar-vortex-avoid-pitfalls.

Conclusion

The data in this paper demonstrates the central flaw in the mandatory capacity markets — that the construction of new power plants requires stable financial arrangements and not the volatile pricing and frequently changing rules that characterize the capacity market construct.

As the electricity industry faces new challenges from environmental regulations, retiring baseload facilities, and an increased reliance on natural gas, it is crucial that the RTOs and FERC revisit the mandatory capacity markets paradigm.

It is time to think outside the capacity markets box and support approaches to resource development that incorporate long-term planning, bilateral contracting, utility ownership, and demand-side approaches without the impediments posed by the complex rules of RTO centralized capacity markets.

Sources of Data

Data on new generation were obtained from two primary sources:

- The Energy Infrastructure Update issued each month by FERC.[20] These reports provide monthly and cumulative data on new natural gas facilities (pipelines, storage and liquefied natural gas), hydropower (license filed or issued, and facility placed in service), electric generation capacity, and transmission projects. For each of these categories, FERC staff selects certain projects to highlight and provides brief project descriptions, which often provide information on ownership or contracting arrangements.
- The U.S. Energy Information Administration (EIA) Electric Power Monthly, Table 6.3 (New Utility Scale Generating Units by Operating Company, Plant and Month) for 2014.[21] This table provides the unit name, type of producer, state, capacity, technology and month of completion. Information on the financial arrangements was generally obtained from the owner or purchaser's web site, local newspapers or other publications.

20 Office of Energy Projects, Federal Energy Regulatory Commission, *Energy Infrastructure Update* (January—December 2014), http://www.ferc.gov/legal/staff-reports.asp.

21 U.S. Energy Information Administration, *Electric Power Monthly,* February 2015, http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_03.

The following sources were also used to supplement these data:

- American Wind Energy Association, US Wind Industry Fourth Quarter 2014 Market Report.
- U.S. Department of Energy (DOE), Fuel Cell Technologies Market Report 2014.
- U.S. DOE, Global Storage Database

Each of these sources provided somewhat different information, including different months or years of completion or different capacity data, requiring verification through an additional source, such as the owner's web site or a local news article. Data on new generation constructed in 2014 are presented in the discussion and tables in this paper.[22]

22 For a more detailed analysis of the fuel mix of new and planned capacity, see *America's Electric Generation Capacity: 2015 Update,* available at http://www.publicpower.org/files/PDFs/APPA_Generation_Capacity.pdf. This study has a higher amount of new generating capacity due to the use of additional sources of data outside of that provided by the US EIA.

Appendix A: Twenty Largest Electric Generating Projects Completed in 2014

Name	Technology		State	Financial Arrangement	Purchaser/ Hedge Provider	Seller/ Developer/Owner	Type of Utility
1 Port Westward Unit 2	Natural Gas	220	OR	Ownership by Utility		Portland General Electric	IOU
2 Copper Mountain Solar 3	Solar	250	NV		Southern California Public Power Authority	Sempra U.S. Gas & Power and ConEd Development	Public Power
3 Palo Duro	Wind	250	TX	Contract with Utility	Xcel Energy	NextEra Energy Resources	IOU
4 Lundgren	Wind	251	IA	Ownership by Utility		MidAmerican Energy Co	
5 Deer Park	Natural Gas	260	TX	Contract for Steam	Shell Purchases Steam	Calpine	
6 Channel Energy Center Expansion	Natural Gas	260	TX	Contract with Customer	LyondellBasell's Houston Refining L.P	Calpine	
7 Tucannon River	Wind	267	WA	Ownership by Utility		Portland General Electric	IOU
8 Mojave Solar	Solar	280	CA	Contract with Utility	Pacific Gas and Electric	Mojave Solar	IOU
9 Miami Wind	Wind	288	TX	Financial Hedge	Not specified	Invernegy	
10 Agua Caliente	Solar	290	AZ	Contract with Utility	Pacific Gas & Electric	NRG Energy	IOU
11 Desert Sunlight	Solar	550	CA	Contract with Utility	Southern California Edison, Pacific Gas & Electric	NextEra Energy, GE Energy Financial Services, Sumitomo	IOU
12 Thomas C Ferguson	Natural Gas	556	TX	Ownership by Utility		Lower Colorado River Authority	Public Power
13 Nine Mile Point	Natural Gas	561	LA	Ownership by Utility		Entergy Lousiana	IOU
14 Lake Side 2	Natural Gas	645	UT	Ownership by Utility		PacifiCorp	IOU
15 Kemper	Natural Gas	696	MS	Ownership by Utility		Mississippi Power	IOU
16 West Deptford Energy Station	Natural Gas	738	NJ	Sale into the Market	Sale into market	LS Power	
17 Panda Sherman	Natural Gas	758	TX	Financial Hedge	3M Retirement Income Plan	Panda Power Funds	
18 Panda Temple	Natural Gas	758	TX	Financial Hedge	3M Retirement Income Plan	Panda Power Funds	
19 Riviera Beach	Natural Gas	1,250	FL	Ownership by Utility		Florida Power & Light Co	IOU
20 Warren Power	Natural Gas	1,329	VA	Ownership by Utility		Dominion Virginia Power	IOU
	Total	10,457					
	% of Total	59%					

Appendix B
Capacity Markets Primer

Capacity markets are complex constructs operated by entities known as regional transmission organizations (RTOs). RTOs are large bureaucratic, quasi-governmental entities that operate markets for capacity, electricity and other services, control transmission, dispatch generation and ensure the reliability of the grid within their region.

The capacity markets provide payments to owners of power plants who agree to stand ready to supply power when needed or to customers who agree to curtail power use when called upon (known as demand response). Capacity is the maximum amount of electricity that a power plant is designed to produce or that a customer is willing to curtail, stated in megawatts (MW). An adequate supply of capacity at all times is necessary to ensure a reliable supply of power, and the intent of capacity payments is to cover power plants' fixed capital and other costs not recovered through electricity sales and other markets. Prior to the creation of capacity markets, many unregulated generation owners argued that the energy markets were not providing sufficient revenue for the construction of new resources and that an extra market was needed to provide this so-called "missing money." But the capacity markets instead provided excess revenue to a large segment of these unregulated generators.

The RTO-operated capacity markets in the mid-Atlantic, New England, and part of New York are mandatory markets because all capacity must be bought and sold through these constructs. Because of the significant amount of revenue earned from these markets and the approval by the Federal Energy Regulatory Commission (FERC) of market rules that restrict new supply, owners of unregulated merchant generation have been advocating for similar mandatory capacity markets in other RTOs in the Midwest, California and Texas.

How do capacity markets work?

Each RTO establishes a reliability standard for all load-serving entities (such as public power utilities). This standard is the MW of capacity these entities must have in place through ownership, contracts or market purchases. The capacity markets hold periodic auctions where capacity is offered and purchased, typically once a year. These auctions produce a single price per MW that will be paid to all capacity resources, regardless of the type and cost. All customers within the RTO region pay the costs of these capacity payments, though there is no requirement that the generation owners actually use the revenue to build new power plants.

With a few exceptions, that capacity price will be in place for one year in a future time period, typically three years after the auction. RTOs also hold incremental auctions to allow for the procurement of additional capacity that may be needed in the near term.

Resources can only be counted toward the RTO reliability standard if they "clear" the auction for the applicable year, meaning that the resource submitted an offer below the clearing price. Until recently, capacity owned by a utility or subject to a long-term contract could offer to sell into the auction at a zero price to ensure such clearing. Because such resources are paid under another arrangement, they are indifferent to the capacity auction price and submit a zero offer as a "price taker."

Are the capacity markets the least-cost means to achieve reliability?

These constructs are costing consumers billions of dollars for little in return, for the following reasons:

- **Different resources have different costs.** In these markets, a 50-year old coal plant is paid the same amount per MW and for the same duration as is a brand new highly efficient combined-cycle natural gas plant as is an agreement by a factory to curtail load when needed. As a result, excess windfall revenue is paid to the older depreciated plants and the revenue stream is not stable enough to attract investors in new resources.
- **The bulk of revenue has been paid to existing plants.** In the PJM Interconnection (primarily covering Maryland, New Jersey, Pennsylvania, Virginia, West Virginia, Ohio, northern Illinois, and Delaware), $88 billion has been paid or will be paid by consumers to generators and other capacity providers. Yet over 90 percent of this revenue has been committed or paid to existing generation, although many older plants have paid off much of their fixed costs. Moreover, most of the new generation capacity that has been built was done so under utility ownership and long-term contracts, not as a result of capacity market payments. In New England, of the approximately $15 billion committed or spent thus far, just 3 percent has been for new generation.
- **Capacity markets do not ensure an appropriate mix of resource types.** Because the capacity markets do not distinguish between technology types or specific locations on the grid, critical needs are not addressed,

including adequate flexible ramping capability to match the variability of renewable resources, reliability gaps created by retiring coal plants, the coordination of natural gas infrastructure and delivery with the significant expansion of natural gas generation. As a result, the RTOs often create systems of side payments to ensure reliability, such as direct payments through what are known as reliability-must-run agreements to coal plants to remain in place to ensure reliability.

- **Price signals are not effective.** If transmission congestion limits the ability of capacity in one area to deliver lower cost power to another zone, the more congested zones may have a higher price. The theory behind zonal price differentials is that higher prices will act as a "signal" for the development of new generation or transmission. But such higher prices are not effective signals because owners of generation have no financial interest in building new resources and lowering prices for their existing units; investors seek steady and predictable revenue flows, not fluctuating prices; and many other factors influence the decision to build, including land and transmission availability, local acceptance, and environmental rules. Transmission construction may alleviate these price differentials, in which case, the consumer has paid both for higher prices and for the cost of the transmission.

Do capacity markets encourage new, cleaner generation?

As described, the capacity markets by design do not incent newer resources. A few years ago, several states located within RTOs became frustrated with the lack of new, more efficient generation given the billions of dollars spent on capacity payments, and sought to take control of their energy resource future and protect their residents from high electricity prices. New Jersey, Maryland and Connecticut all took steps to establish competitive bidding processes for the procurement of capacity for long-term bilateral contracts.

Fearful of the lower prices that would result from the entry of new generation resulting from these state efforts, owners of existing power plants sought to block this competition by obtaining approval from FERC for "minimum offer price rules" or "buyer-side" mitigation rules that impose a floor price on the offers from new resources, making it more difficult for these new plants to clear the auctions. (These rules apply just to natural gas units in PJM but to all resource types in New England and parts of New York.) A failure to clear means that the load-serving entities would pay twice for new capacity (once for the plant and a second time through the market). This risk makes investment in such new plants more difficult to obtain, which raises the cost of capital.

When the capacity markets were created in PJM and New England, the states, public power and cooperative utilities carefully negotiated exemptions from these minimum offer price rules for resources built by local utilities to supply their own load or for a state to address a reliability concern. But in response to the complaints from generators, FERC eliminated these negotiated and reasonable exemptions in 2011. In New York City, generation owners used buyer-side price mitigation rules in that capacity market to fight the entry of a new, more efficient power plant, which has a long-term contract with the New York Power Authority

Following the removal of the exemptions, in PJM, negotiations among merchant generators, industrial customers, and public power and cooperative utilities in 2012 resulted in an agreement providing for, among other things, a minimum offer price rule exemption for self-supply resources that meet certain criteria. FERC also recently granted an exemption for self-supply and renewable resources in the New York ISO, also subject to specific criteria, the details of which are to be worked out in the stakeholder process.

What is the alternative to the capacity markets?

APPA has proposed that FERC mandate a transition from mandatory capacity markets to voluntary residual markets, with the primary procurement of capacity conducted by states and local public power and cooperative utilities through bilateral contracts. This new paradigm would replace an irrational, centrally administered construct with the ability of states and local utilities to determine the optimal mix of resources, and to structure a portfolio of contracts for supply and demand-side resources of varying lengths and terms, or direct ownership that would lower costs to consumers, maximize reliability and provide environmental benefits.

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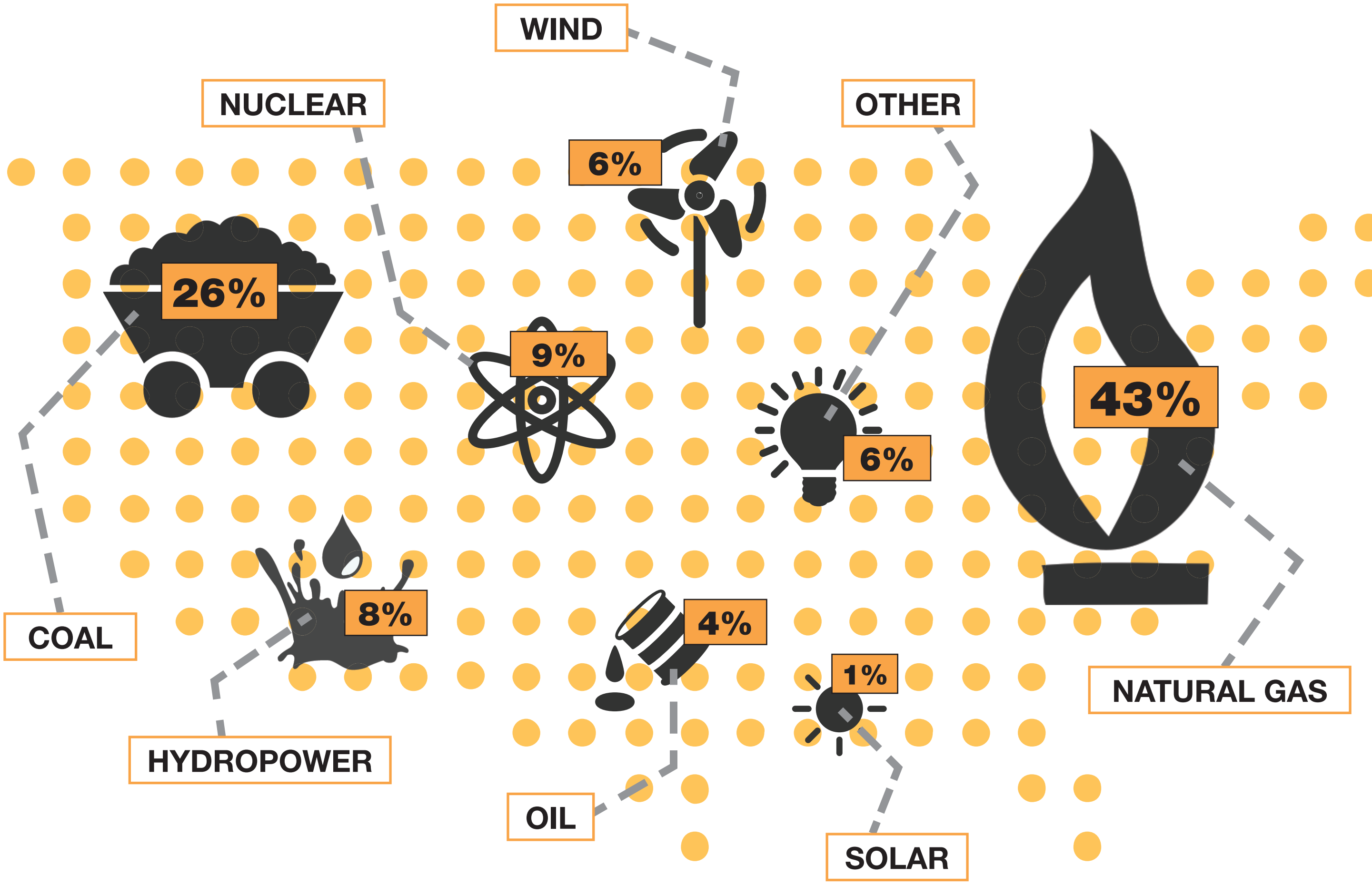

America's Electricity Generation Capacity

2016 Update

American Public Power Association

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The American Public Power Association represents not-for-profit, community-owned electric utilities that power homes, businesses and streets in nearly 2,000 towns and cities, serving 47 million Americans. More at www.PublicPower.org.

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America's Electricity Generation Capacity

2016 Update

Prepared by
Paul Zummo, Manager, Policy Research and Analysis
American Public Power Association

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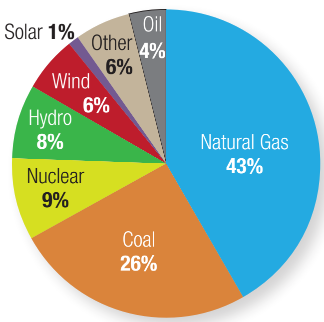


The American Public Power Association presents the tenth annual report on current and forthcoming electricity generation capacity in America by types of fuel, location, and ownership type.

Currently, America has just over 1.17 million megawatts of generation capacity.

The largest fuel source is natural gas, accounting for nearly 43 percent of all generation capacity. Coal, with a share of just over 26 percent of capacity, is the second largest generation source. Nuclear, hydro, and wind together account for nearly 24 percent of capacity. Solar currently constitutes a little bit more than one percent of all capacity.

This report analyzes prospective generation capacity in four categories — under construction, permitted, application pending, and proposed.

Nearly 341,000 MW of new generation capacity is under development in the United States — 87,000 MW under construction or permitted, and just under 254,000 MW proposed or pending application.

Natural gas will continue to be the top fuel source in the near and distant future, followed by wind. A growing amount of generating capacity is expected to be fueled by solar. In fact, solar constitutes just over 11 percent of all capacity for plants under construction and that have permits to start building.

The report shows future generating capacity by Regional Transmission Organization region. Approximately one-third of future generating capacity would be in non-RTO regions and two-thirds in RTO regions, which is the same as the current capacity mix.

When we look at capacity additions, cancellations, and retirements from 2008 to 2015, we see that natural gas is the only resource for which adwditions outnumber cancellations. For all other resources, far more capacity was cancelled than was added. Over 18,000 MW of capacity was retired in 2015 alone, of which coal accounted for almost 80 percent.

This report also includes information on capacity factors and construction costs. Costs to construct new generation vary considerably by fuel type, with natural gas generally cheaper on a per-MW basis than almost all forms of generation, and renewable forms of generation being more expensive.

While the overall capacity mix in the United States will change, it will do so at a gradual pace. Coal and other traditional forms of electric generation are being displaced by wind, solar, and other forms of renewable generation. However; natural gas continues to be the most popular fuel choice due to costs and efficiency considerations. Environmental regulations as well as increases in natural gas spot prices could spur increased deployment of alternative resources, but the immediate outlook for generation capacity shows continued reliance on natural gas and traditional forms of generation.

Source: Data analyzed for this report was taken from the Ventyx Velocity Suite database, accessed January 2016.

Section 1
Current Generation Capacity

TABLE 1.1 shows the sources from which electricity is currently generated in America. Current nameplate capacity includes capacity labeled as standby, but not mothballed or out of service.

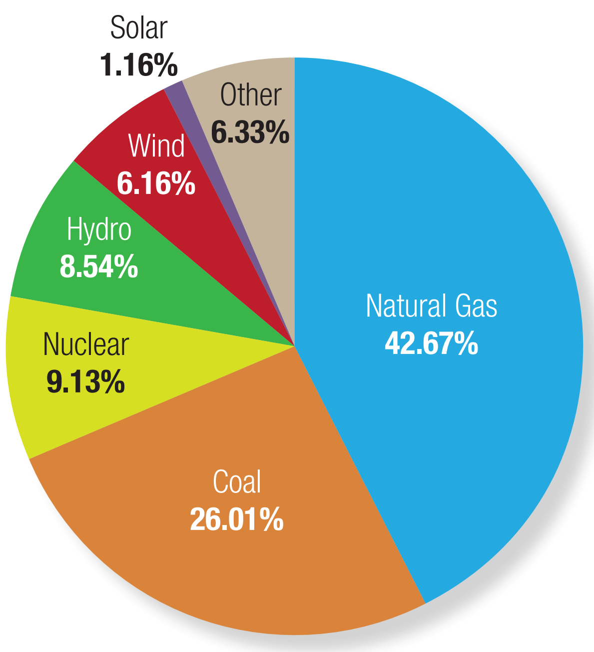


TABLE 1.1

2016 Current Electricity Generation Capacity, by Fuel Type

Primary Fuel Type	Capacity (MW)	Share
Natural Gas	500,207.34	42.67%
Coal	304,977.37	26.01%
Nuclear	107,034.52	9.13%
Hydro	100,076.62	8.54%
Wind	72,216.95	6.16%
Distillate Fuel Oil	24,304.83	2.07%
Residual Fuel Oil	18,979.50	1.62%
Solar	13,638.05	1.16%
Wood/Wood Waste Solids	5,180.37	0.44%
Wood Waste Liquids	4,800.45	0.41%
Geothermal	3,902.65	0.33%
Waste	2,788.25	0.24%
Petroleum Coke	2,774.20	0.24%
Landfill Gas	2,669.18	0.23%
Other Gas	2,046.80	0.17%
Kerosene	1,888.40	0.16%
Waste Heat	1,155.93	0.10%
Blast Furnace Gas	929.60	0.08%
Jet Fuel	537.74	0.05%
Biomass Gases	461.03	0.04%
Purchased Steam	419.40	0.04%
Agriculture Byproduct	416.70	0.04%
Other	349.54	0.03%
Biomass Solids	292.16	0.02%
Biomass Liquids	126.69	0.01%
Waste Oil and Other Oil	119.91	0.01%
Refuse	15.79	0.00%
Biomass Other	7.10	0.00%
Propane	1.63	0.00%
Total	**1,172,318.69**	**100.00%**

TABLE 1.2 shows how America's current generation capacity is distributed through the various regions defined by the North American Electric Reliability Corporation.

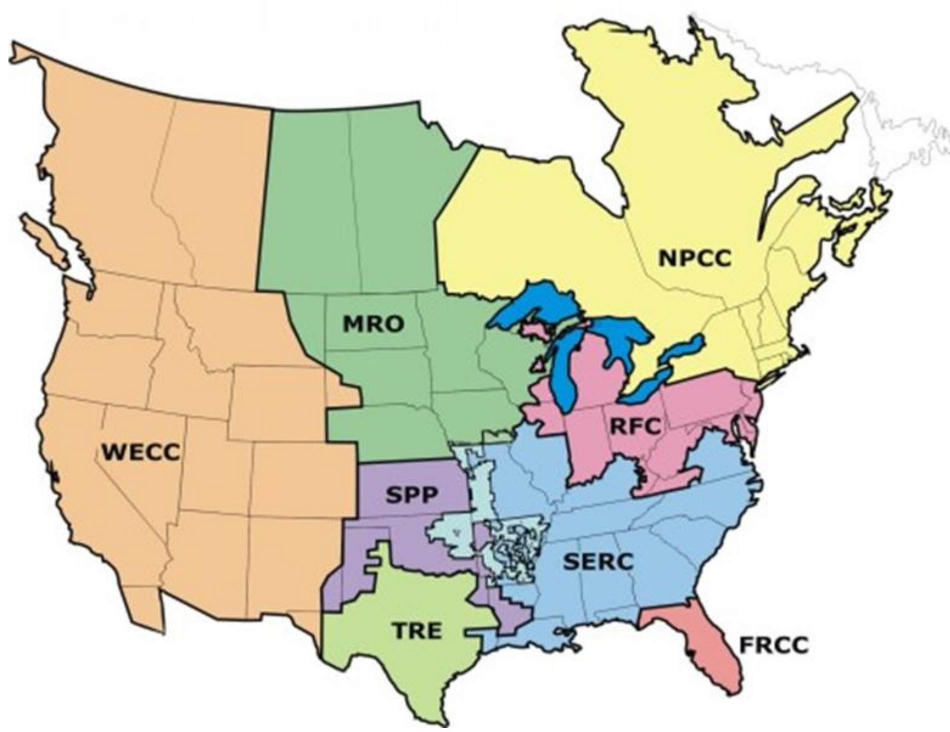
TABLE 1.2

2016 Current Electricity Generation Capacity, by Region

Region	Capacity (MW)	Share
SERC	296,559.46	25.30%
RFC	241,935.07	20.64%
WECC	228,018.66	19.45%
ERCOT	108,873.17	9.29%
NPCC	83,596.06	7.13%
SPP	74,500.61	6.35%
MRO	67,119.19	5.73%
FRCC	65,615.80	5.60%
HCC	3,065.81	0.26%
ASCC	3,034.86	0.26%
Total	**1,172,318.69**	**100.00%**

Regions Defined by NERC

ASCC: Alaska Systems Coordinating Council (not shown on map)
ERCOT: Electric Reliability Council of Texas
FRCC: Florida Reliability Coordinating Council
HCC: Hawaii Coordinating Council (not shown on map)
NPCC: Northeast Power Coordinating Council
MRO: Midwest Reliability Organization
RFC: Reliability First Corporation
SERC: Southeastern Electric Reliability Council
SPP: Southwest Power Pool
WECC: Western Electricity Coordinating Council



As seen in TABLE 1.3, over 168,000 MW of current generation capacity was added between 2008 and 2015. Nearly three-quarters of this new capacity is fueled by natural gas or wind, with another 11 percent coming from coal.

TABLE 1.3

Generation Capacity Additions by Fuel Type, 2008 - 2015

Primary Fuel Type	Capacity (MW)	Share
Natural Gas	70,887.46	42.09%
Wind	55,904.30	33.19%
Coal	19,134.70	11.36%
Solar	13,080.50	7.77%
Wood/Wood Waste Solids	1,332.58	0.79%
Hydro	1,282.87	0.76%
Landfill Gas	1,202.91	0.71%
Petroleum Coke	1,048.20	0.62%
Distillate Fuel Oil	852.74	0.51%
Other Gas	850.40	0.50%
Geothermal	717.49	0.43%
Waste Heat	483.23	0.29%
Kerosene	440.00	0.26%
Wood Waste Liquids	362.30	0.22%
Biomass Gases	245.44	0.15%
Waste	131.10	0.08%
Biomass Liquids	123.09	0.07%
Biomass Solids	121.43	0.07%
Blast Furnace Gas	101.00	0.06%
Agriculture Byproduct	46.10	0.03%
Other	26.50	0.02%
Refuse	15.79	0.01%
Waste Oil and Other Oil	9.20	0.01%
Jet Fuel	6.40	0.00%
Biomass Other	5.10	0.00%
Propane	1.63	0.00%
Purchased Steam	1.00	0.00%
Total	**168,413.47**	**100.00%**

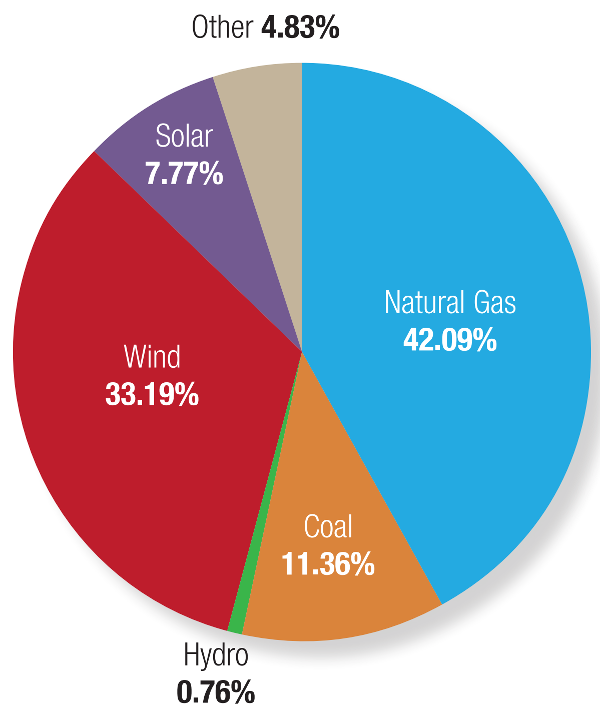


TABLE 1.4 shows that in 2015 alone, over 14,000 MW of generation began operating, with natural gas, wind, and solar accounting for 96 percent of the new capacity.

TABLE 1.4

Generation Capacity Additions by Fuel Type, 2015

Primary Fuel Type	Capacity (MW)	Share
Wind	6,151.78	46.38%
Natural Gas	4,971.80	37.49%
Solar	1,643.91	12.39%
Wood/Wood Waste Solids	161.50	1.22%
Hydro	127.14	0.96%
Waste	95.00	0.72%
Geothermal	45.00	0.34%
Landfill Gas	30.30	0.23%
Biomass Gases	16.75	0.13%
Distillate Fuel Oil	13.70	0.10%
Coal	3.00	0.02%
Biomass Other	1.60	0.01%
Jet Fuel	1.20	0.01%
Total	**13,262.67**	**100.00%**

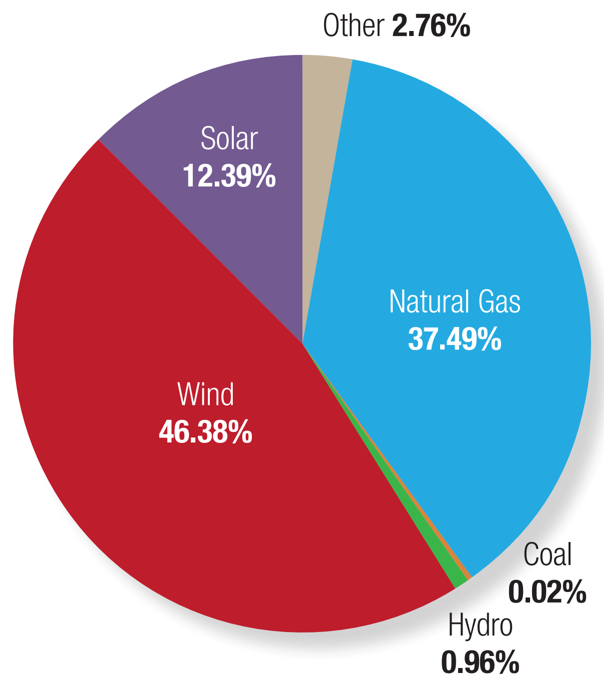
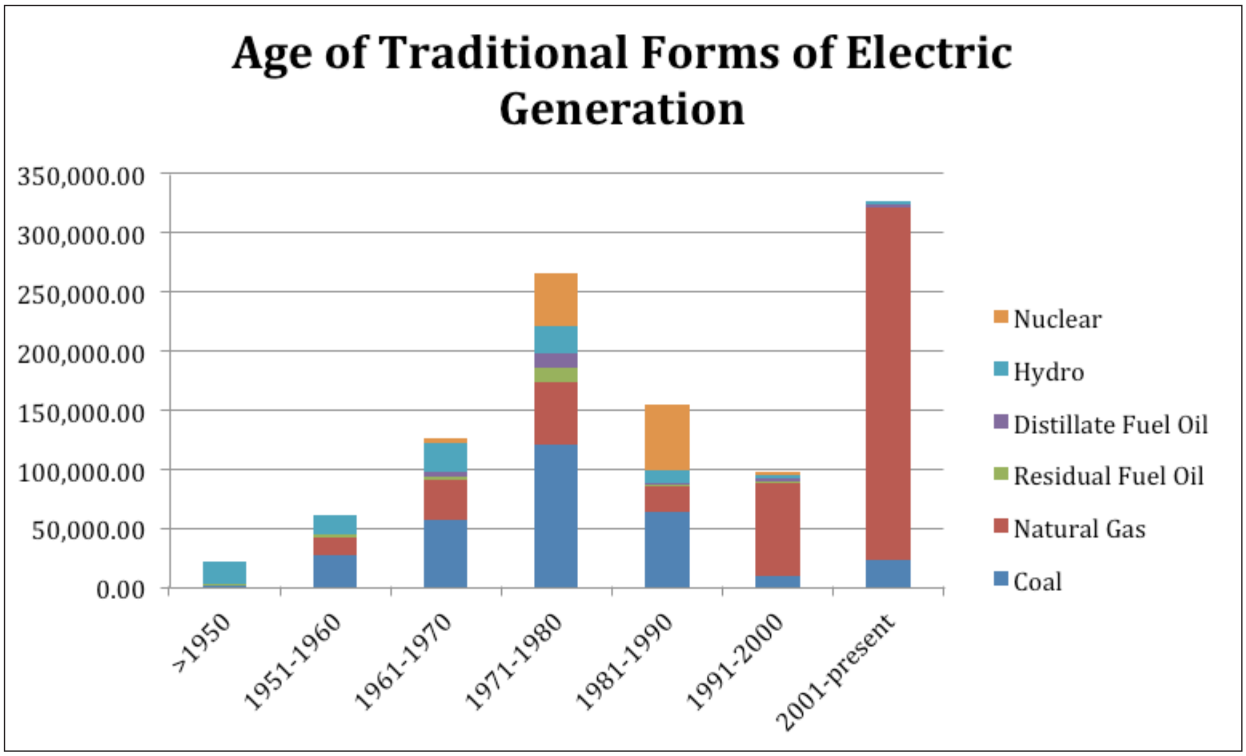


Figure 1.1 shows the age of traditional forms of generating capacity — coal, nuclear, hydro, natural gas, and oil. Most hydro and coal capacity is approximately 40 years old or more, having come online by 1980. Almost all domestic nuclear capacity became operational between 1969 and 1990. While natural gas capacity dates back to the 1950s, the bulk of natural gas capacity is less than 25 years of age. This chart does not show renewable generation, almost all of which came online after 2000.

FIGURE 1.1
Age of Traditional Forms of Electric Generation



Section 2

Future Generating Capacity: Fuel Mix

Tables 2.1 – 2.4 show the fuel makeup of America's future generation capacity.

Table 2.1 shows the sources for the 42,205 MW of generation capacity under construction. Natural gas and wind account for nearly three-quarters of the capacity under construction. Three major nuclear operations in the Southeast account for all nuclear capacity under construction.

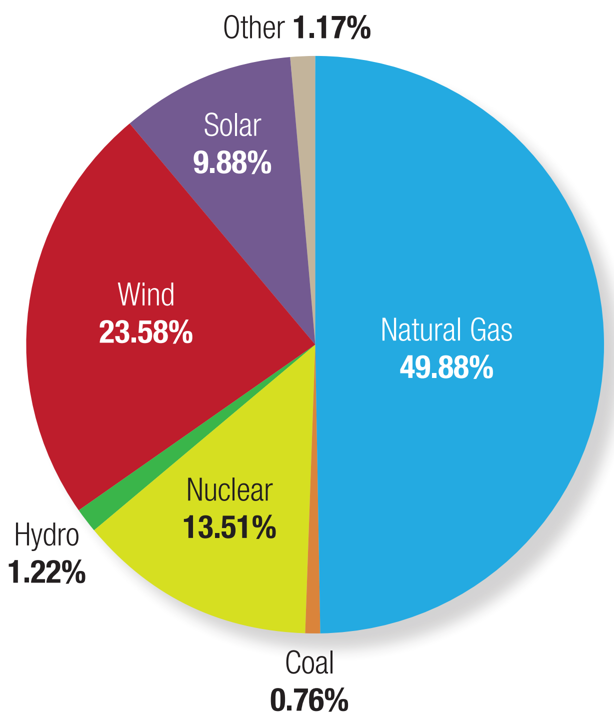


TABLE 2.1

Plants Under Construction, by Fuel Type

Primary Fuel Type	Capacity (MW)	Share
Natural Gas	21,051.53	49.88%
Wind	9,951.20	23.58%
Nuclear	5,703.90	13.51%
Solar	4,170.04	9.88%
Hydro	514.67	1.22%
Coal	320.00	0.76%
Waste	205.70	0.49%
Wood Waste Liquids	75.00	0.18%
Biomass Solids	64.50	0.15%
Landfill Gas	51.30	0.12%
Wood/Wood Waste Solids	50.00	0.12%
Geothermal	24.18	0.06%
Distillate Fuel Oil	22.40	0.05%
Biomass Gases	1.00	0.00%
Other	0.00	0.00%
Total	**42,205.41**	**100.00%**

Table 2.2 shows the fuel makeup for plants that have received permits to construct 45,078 MW of capacity overall but that have not yet started construction. Natural gas is the leading resource choice for permitted plants, accounting for nearly half of the new capacity. Wind is second and accounts for nearly a quarter of potential capacity.

Table 2.3 shows the fuel mix for the 73,442 MW of capacity awaiting approval of applications. Natural gas is the leading resource choice, accounting for nearly 50 percent of the capacity. Nuclear, solar, and wind each account for over 10 percent of capacity pending application.

TABLE 2.2

Permitted Plants, by Fuel Type

Primary Fuel Type	Capacity (MW)	Share
Natural Gas	21,936.90	48.66%
Wind	11,432.14	25.36%
Solar	5,901.69	13.09%
Coal	2,335.00	5.18%
Nuclear	1,500.00	3.33%
Geothermal	608.90	1.35%
Other	587.00	1.30%
Hydro	469.69	1.04%
Wood/Wood Waste Solids	191.40	0.42%
Waste	59.20	0.13%
Agriculture Byproduct	49.90	0.11%
Landfill Gas	5.80	0.01%
Total	**45,077.62**	**100.00%**

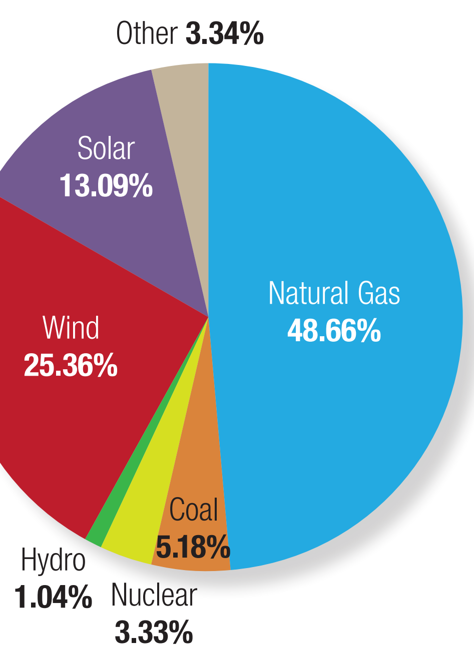


TABLE 2.3

Plants Pending Application, by Fuel Type

Primary Fuel Type	Capacity (MW)	Share
Natural Gas	36,295.10	49.42%
Nuclear	11,016.00	15.00%
Solar	10,928.25	14.88%
Wind	8,592.70	11.70%
Hydro	4,522.84	6.16%
Petroleum Coke	1,137.00	1.55%
Geothermal	396.00	0.54%
Coal	270.00	0.37%
Waste Heat	95.00	0.13%
Wood/Wood Waste Solids	62.50	0.09%
Liquefied Natural Gas	50.63	0.07%
Agriculture Byproduct	50.00	0.07%
Distillate Fuel Oil	16.00	0.02%
Landfill Gas	5.62	0.01%
Biomass Gases	4.00	0.01%
Total	**73,441.64**	**100.00%**

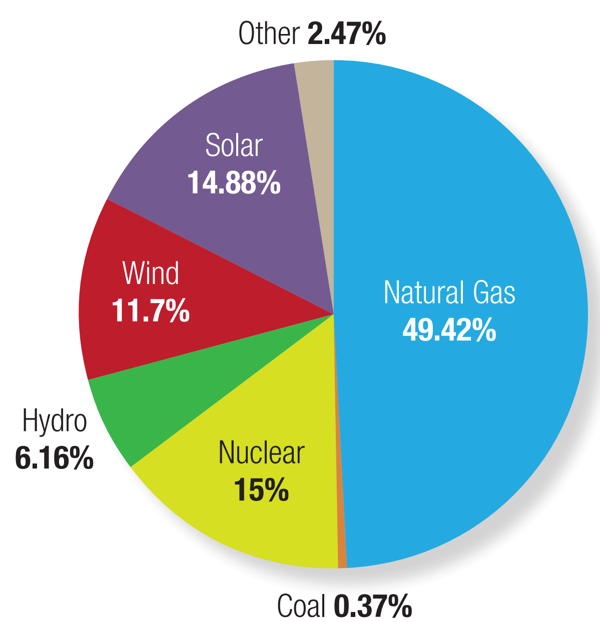
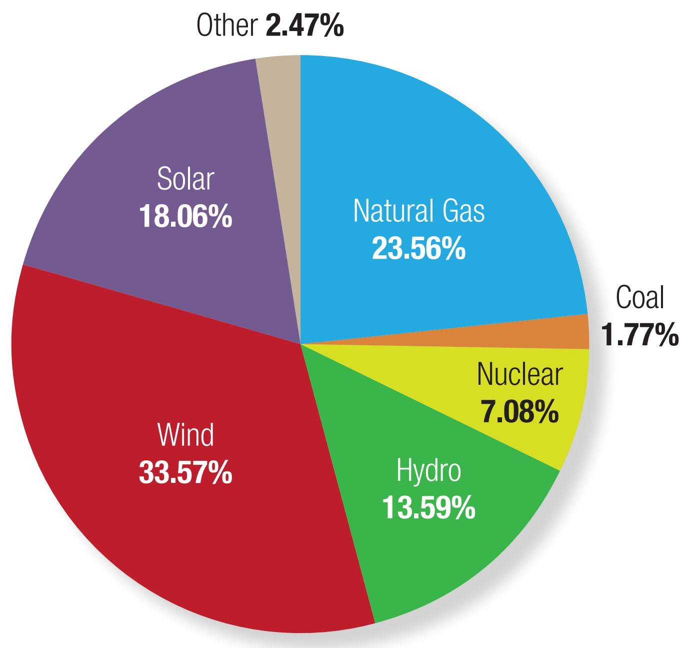


Table 2.4 shows the resource mix for the 180,261 MW of capacity still in the planning stage. This is the earliest and most uncertain stage of development, and includes units that are least likely to be built. Wind power accounts for approximately one-third of planned capacity with natural gas, hydro, and solar accounting for the bulk of the remaining capacity.

TABLE 2.4

Proposed Plants, by Fuel Type

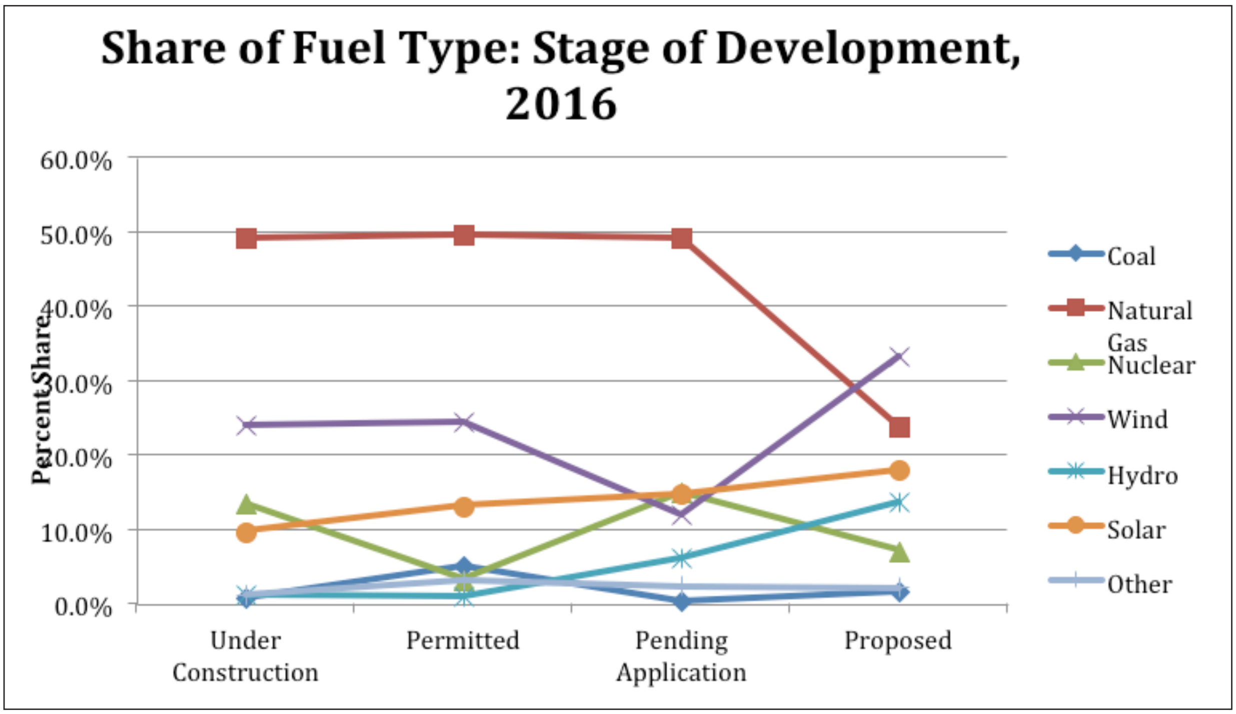
Primary Fuel Type	Nameplate Capacity (MW)	Share
Wind	60,521.86	33.57%
Natural Gas	42,470.11	23.56%
Solar	32,561.65	18.06%
Hydro	24,504.86	13.59%
Nuclear	12,755.00	7.08%
Coal	3,192.00	1.77%
Geothermal	1,589.70	0.88%
Residual Fuel Oil	632.40	0.35%
Wood/Wood Waste Solids	518.08	0.29%
Blast Furnace Gas	500.00	0.28%
Other	307.39	0.17%
Biomass Other	165.10	0.09%
Landfill Gas	125.82	0.07%
Waste Heat	120.00	0.07%
Waste	72.40	0.04%
Jet Fuel	60.00	0.03%
Distillate Fuel Oil	54.35	0.03%
Biomass Solids	41.00	0.02%
Biomass Gases	40.62	0.02%
Biomass Liquids	19.00	0.01%
Agriculture Byproduct	6.30	0.00%
Other Gas	3.50	0.00%
Total	**180,261.14**	**100.00%**



Section 3
Future Generating Capacity: Development Stages

Figure 3.1 tracks the major fuel sources in each stage of development. Natural gas is the dominant fuel choice in the first three stages — under construction, permitted, and pending application. Wind is the leading source of generating capacity in the proposed capacity stage. Figure 2.1 also shows that the resource mix is more balanced in the earlier stages of development.

FIGURE 3.1
Share of Fuel Type: Stage of Development, 2016



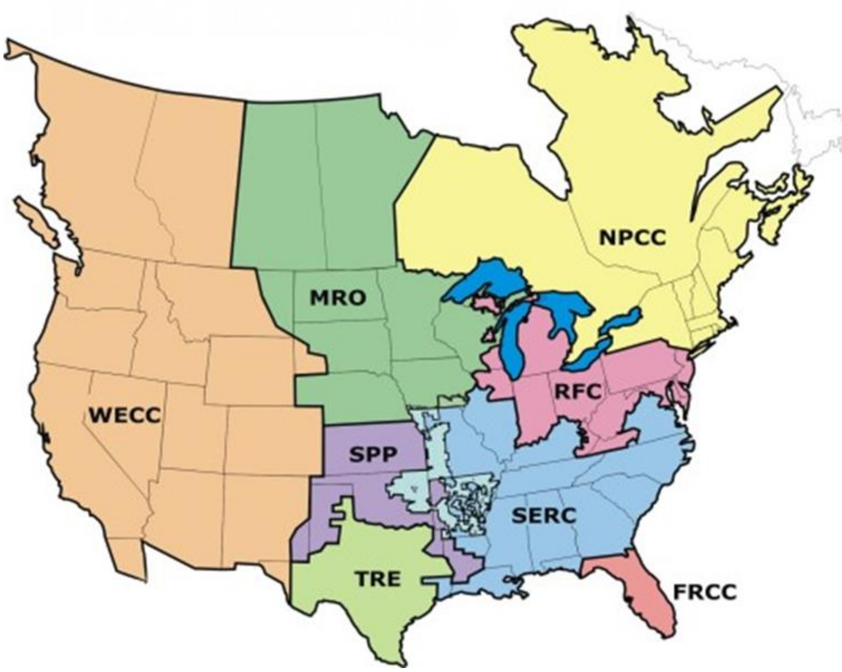
Section 4
Future Generating Capacity: Regional Mix

Tables 4.1 – 4.4 show where the new plants are being built or planned for construction by North American Electric Reliability Corporation regions. (See Appendix 1 for definition of regions and included states and Appendix 2 for the fuel mix for each region.)

TABLE 4.1 shows that four regions account for roughly three-quarters of the capacity under construction.

TABLE 4.1
Plants Under Construction, by NERC Region

Region	Capacity (MW)	Share
RFC	9,478.40	22.46%
SERC	9,407.72	22.29%
WECC	7,008.76	16.61%
ERCOT	6,038.10	14.31%
SPP	3,791.22	8.98%
MRO	2,666.25	6.32%
FRCC	2,491.40	5.90%
NPCC	1,129.87	2.68%
ASCC	135.90	0.32%
HCC	57.80	0.14%
Total	**42,205.41**	**100.00%**



Regions Defined by NERC

ASCC: Alaska Systems Coordinating Council (not shown in map)
ERCOT: Electric Reliability Council of Texas
FRCC: Florida Reliability Coordinating Council
HCC: Hawaii Coordinating Council (not shown on map)
NPCC: Northeast Power Coordinating Council
MRO: Midwest Reliability Organization
RFC: Reliability First Corporation
SERC: Southeastern Electric Reliability Council
SPP: Southwest Power Pool
WECC: Western Electricity Coordinating Council

Table 4.2 shows that the Western Electricity Coordinating Council and Electric Reliability Council of Texas regions account for over half of the capacity at this stage.

Tables 4.3 and 4.4 show plants in the pending application and proposed categories, in both of which WECC has far more potential capacity than any other region.

TABLE 4.2

Permitted Plants, by NERC Region

Region	Nameplate Capacity (MW)	Share
WECC	11,778.65	26.13%
ERCOT	11,614.70	25.77%
RFC	7,464.40	16.56%
SERC	4,094.69	9.08%
NPCC	3,820.47	8.48%
MRO	2,295.60	5.09%
SPP	2,222.80	4.93%
FRCC	1,413.00	3.13%
ASCC	339.70	0.75%
HCC	33.62	0.07%
Total	**45,077.62**	**100.00%**

TABLE 4.3

Plants Pending Application, by Region

Region	Capacity (MW)	Share
WECC	25,016.10	34.06%
ERCOT	17,592.90	23.95%
RFC	12,157.08	16.55%
SERC	8,327.57	11.34%
NPCC	4,235.38	5.77%
FRCC	3,006.00	4.09%
MRO	1,658.88	2.26%
SPP	1,184.80	1.61%
HCC	194.13	0.26%
ASCC	68.80	0.09%
Total	**73,441.64**	**100.00%**

TABLE 4.4

Proposed Plants, by Region

Region	Capacity (MW)	Share
WECC	73,968.39	41.03%
RFC	25,096.94	13.92%
SERC	23,479.20	13.03%
NPCC	14,235.39	7.90%
MRO	13,919.03	7.72%
ERCOT	12,534.40	6.95%
SPP	7,248.08	4.02%
FRCC	5,702.81	3.16%
ASCC	3,268.74	1.81%
HCC	708.28	0.39%
Total	**180,261.14**	**100.00%**

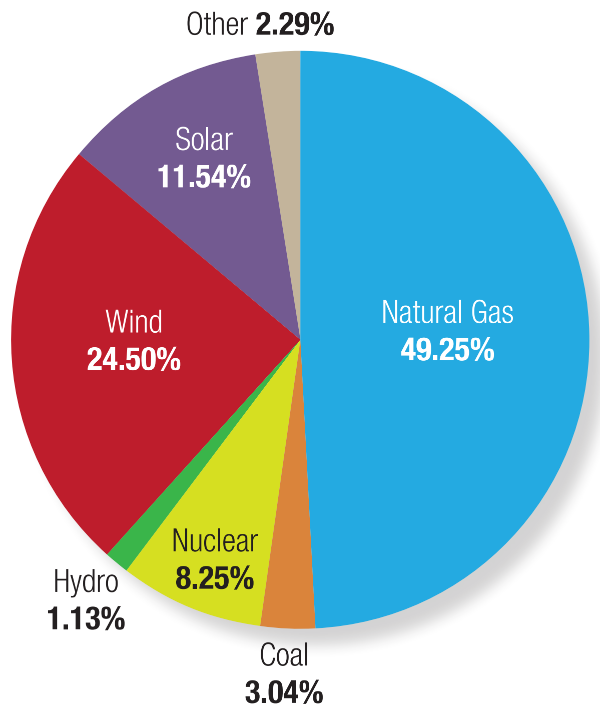
TABLES 4.5 and 4.6 show the fuels of choice for proposed capacity by development stage.

As seen in Table 4.5, for plants most certain to be built — those already under construction or permitted — natural gas and wind account for nearly 74 percent of the capacity, with solar contributing another 11.5 percent.

TABLE 4.5

Plants Permitted and Under Construction, by Fuel Type

Primary Fuel Type	Capacity (MW)	Share
Natural Gas	42,988.43	49.25%
Wind	21,383.34	24.50%
Solar	10,071.73	11.54%
Nuclear	7,203.90	8.25%
Coal	2,655.00	3.04%
Hydro	984.36	1.13%
Geothermal	633.08	0.73%
Other	587.00	0.67%
Waste	264.90	0.30%
Wood/Wood Waste Solids	241.40	0.28%
Wood Waste Liquids	75.00	0.09%
Biomass Solids	64.50	0.07%
Landfill Gas	57.10	0.07%
Agriculture Byproduct	49.90	0.06%
Distillate Fuel Oil	22.40	0.03%
Biomass Gases	1.00	0.00%
Total	**87,283.03**	**100.00%**



Reliability First Corporation, WECC, and ERCOT each account for approximately 20 percent of the capacity under construction and permitted, with another 15 percent located in the Southeastern Electric Reliability Council region. Natural gas is the primary resource in the ERCOT and RFC regions as well as in the Florida Reliability Coordinating Council and Northeast Power Coordinating Council regions. In each of these four regions, natural gas accounts for at least 70 percent of future capacity.

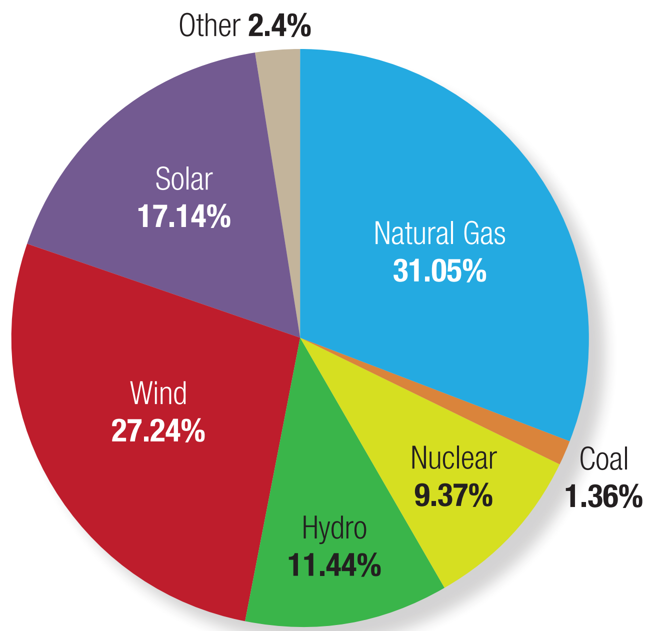
There is a general increase in planned solar capacity. Just over 70 percent of solar capacity in the permitted and under construction stages is located in the WECC region, where solar is the leading fuel choice. Another 20 percent of solar capacity is located in SERC. Four regions account for nearly 80 percent of new wind capacity — ERCOT and WECC as well as the Midwest Reliability Organization and Southwest Power Pool regions.

As seen in table 4.6, for plants in the more distant future — those that are proposed or pending application — the fuel mix tends more toward wind and other renewable resources, compared to plants that are scheduled to come online in the near future. There is slightly more impending natural gas than wind capacity.

TABLE 4.6

Plants Pending Application and Proposed, by Fuel Type

Primary Fuel Type	Nameplate Capacity (MW)	Share
Natural Gas	78,765.21	31.05%
Wind	69,114.56	27.24%
Solar	43,489.90	17.14%
Hydro	29,027.70	11.44%
Nuclear	23,771.00	9.37%
Coal	3,462.00	1.36%
Geothermal	1,985.70	0.78%
Petroleum Coke	1,137.00	0.45%
Residual Fuel Oil	632.40	0.25%
Wood/Wood Waste Solids	580.58	0.23%
Blast Furnace Gas	500.00	0.20%
Other	307.39	0.12%
Waste Heat	215.00	0.08%
Biomass Other	165.10	0.07%
Landfill Gas	131.44	0.05%
Waste	72.40	0.03%
Distillate Fuel Oil	70.35	0.03%
Jet Fuel	60.00	0.02%
Agriculture Byproduct	56.30	0.02%
Liquefied Natural Gas	50.63	0.02%
Biomass Gases	44.62	0.02%
Biomass Solids	41.00	0.02%
Biomass Liquids	19.00	0.01%
Other Gas	3.50	0.00%
Total	**253,702.78**	**100.00%**



Wind is slated to account for twenty percent or more of new capacity in all but the Alaska and Florida regions and is the leading resource in four regions. Over 71 percent of the proposed or application pending solar capacity is located in WECC, a region that accounts for much of the future renewable capacity. Other forms of renewable energy, particularly wood, waste, and waste heat, are more dispersed through the various regions.

Section 5

Future Generating Capacity: Ownership Type

Analysis of future generation capacity by ownership is summarized in Tables 5.1 – 5.4.

TABLE 5.1 shows that for plants under construction, most of the capacity is owned by non-utility generators, while regulated utilities collectively account for over 40 percent of the capacity.

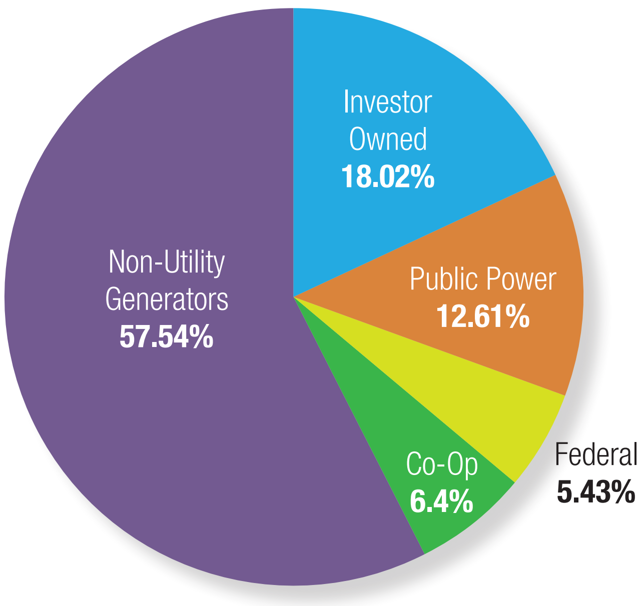


TABLE 5.1

Plants Under Construction, by Ownership

Utility Type	Capacity (MW)	Share
Non-utility Generators	24,285.52	57.54%
Investor Owned	7,607.40	18.02%
Public Power	5,320.42	12.61%
Co-Op	2,701.18	6.40%
Federal	2,290.90	5.43%
Total	**42,205.41**	**100.00%**

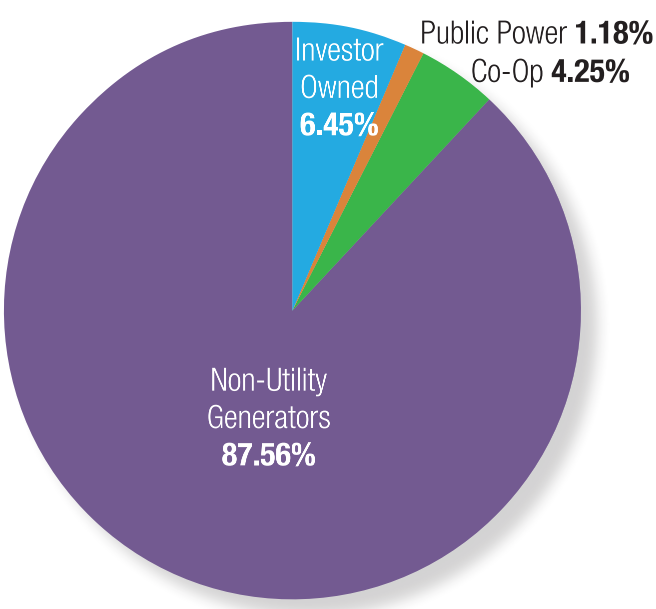


TABLE 5.2

Permitted Plants, by Ownership

Utility Type	Capacity (MW)	Share
Non-utility Generators	39,470.12	87.56%
Investor Owned	2,907.60	6.45%
Co-Op	1,917.20	4.25%
Public Power	531.50	1.18%
Total	**45,077.62**	**100.00%**

TABLES 5.2 – 5.4 show that non-utility generators account for significant capacity in the earlier stages of development.

Of note in TABLE 5.4 is that for proposed plants, generation owned by public power has the largest share of capacity among utilities.

TABLE 5.3

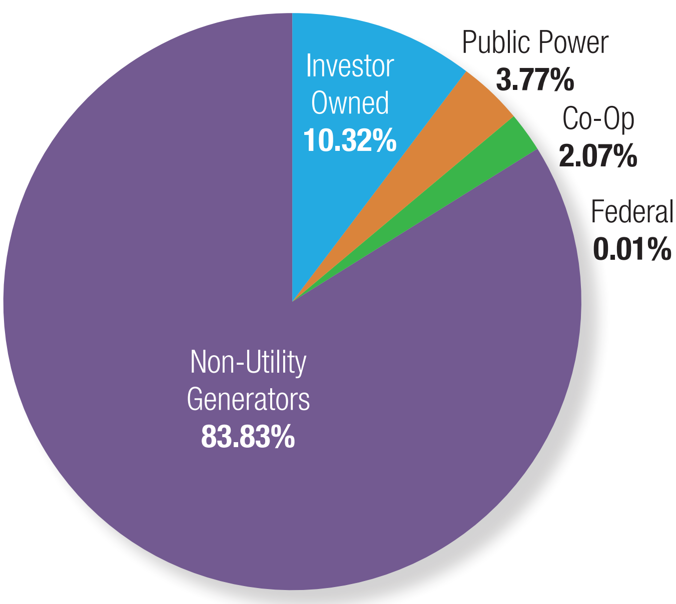
Plants Pending Application, by Ownership Type

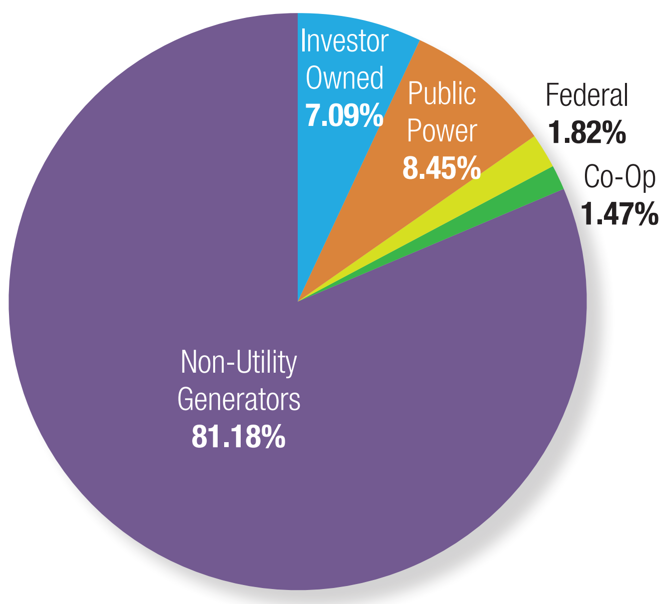
Ownership	Capacity (MW)	Share
Non-utility Generators	61,562.55	83.83%
Investor Owned	7,576.13	10.32%
Public Power	2,768.26	3.77%
Co-Op	1,523.70	2.07%
Federal	11.00	0.01%
Total	**73,441.64**	**100.00%**

TABLE 5.4

Proposed Plants, by Ownership Type

Ownership	Capacity (MW)	Share
Non-utility Generators	146,344.16	81.18%
Public Power	15,225.29	8.45%
Investor Owned	12,771.52	7.09%
Federal	3,278.50	1.82%
Co-Op	2,641.67	1.47%
Total	**180,261.14**	**100.00%**





Section 6

Future Generating Capacity: Regional Transmission Organization

Tables 6.1 – 6.4 show future generating capacity by Regional Transmission Organization region. Approximately one-third of future generating capacity would be in non-RTO regions and two-thirds in RTO regions, which is the same as the current capacity mix.

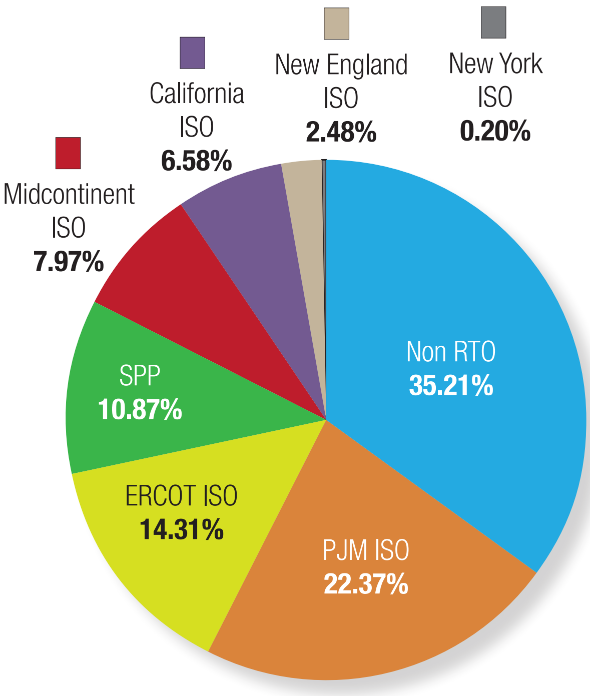


TABLE 6.1

Plants Under Construction, by RTO

RTO Region	Capacity (MW)	Share
Non RTO	14,862.43	35.21%
PJM ISO	9,442.94	22.37%
ERCOT ISO	6,038.10	14.31%
SPP	4,588.05	10.87%
Midcontinent ISO	3,365.17	7.97%
California ISO	2,778.86	6.58%
New England ISO	1,045.82	2.48%
New York ISO	84.05	0.20%
Total	**42,205.41**	**100.00%**

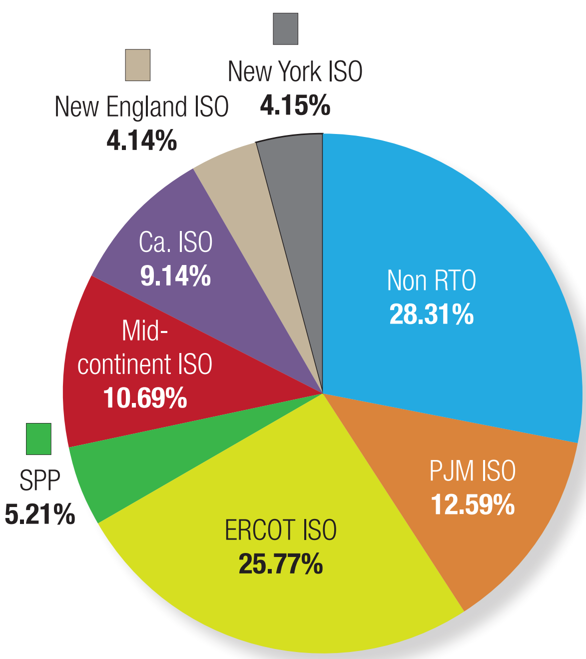


TABLE 6.2

Permitted Plants, by RTO

RTO Region	Capacity (MW)	Share
Non RTO	12,759.31	28.31%
ERCOT ISO	11,614.70	25.77%
PJM ISO	5,674.60	12.59%
Midcontinent ISO	4,819.50	10.69%
California ISO	4,122.05	9.14%
SPP	2,347.00	5.21%
New York ISO	1,872.60	4.15%
New England ISO	1,867.87	4.14%
Total	**45,077.62**	**100.00%**

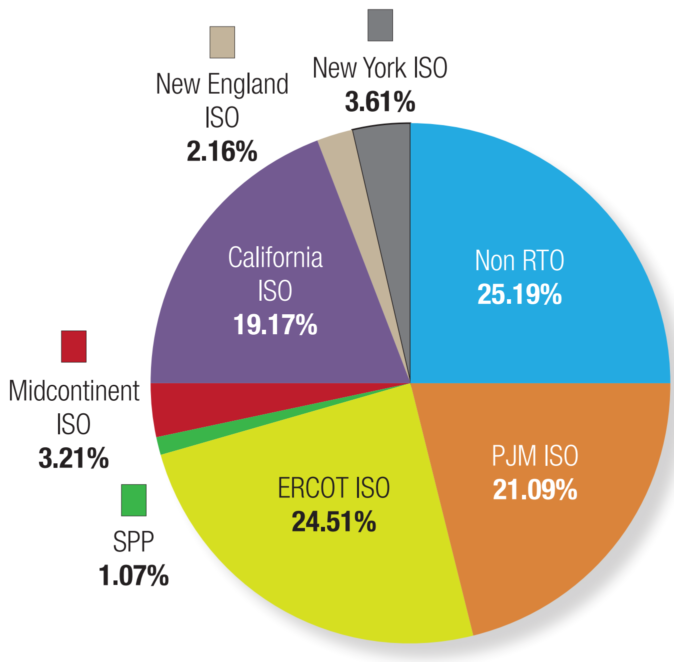


TABLE 6.3

Plants Pending Application, by RTO Region

RTO	Capacity (MW)	Share
Non RTO	18,500.61	25.19%
ERCOT ISO	17,996.90	24.51%
PJM ISO	15,485.48	21.09%
California ISO	14,075.90	19.17%
New York ISO	2,650.80	3.61%
Midcontinent ISO	2,358.58	3.21%
New England ISO	1,584.58	2.16%
SPP	788.80	1.07%
Total	**73,441.64**	**100.00%**

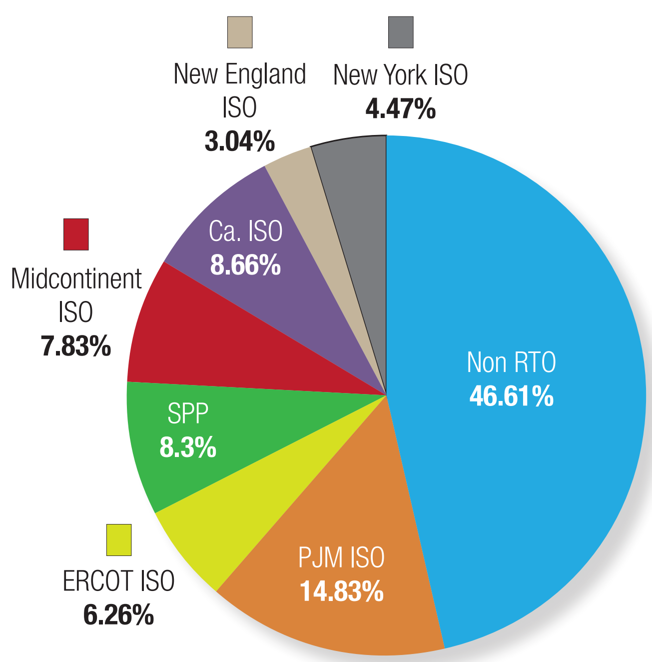
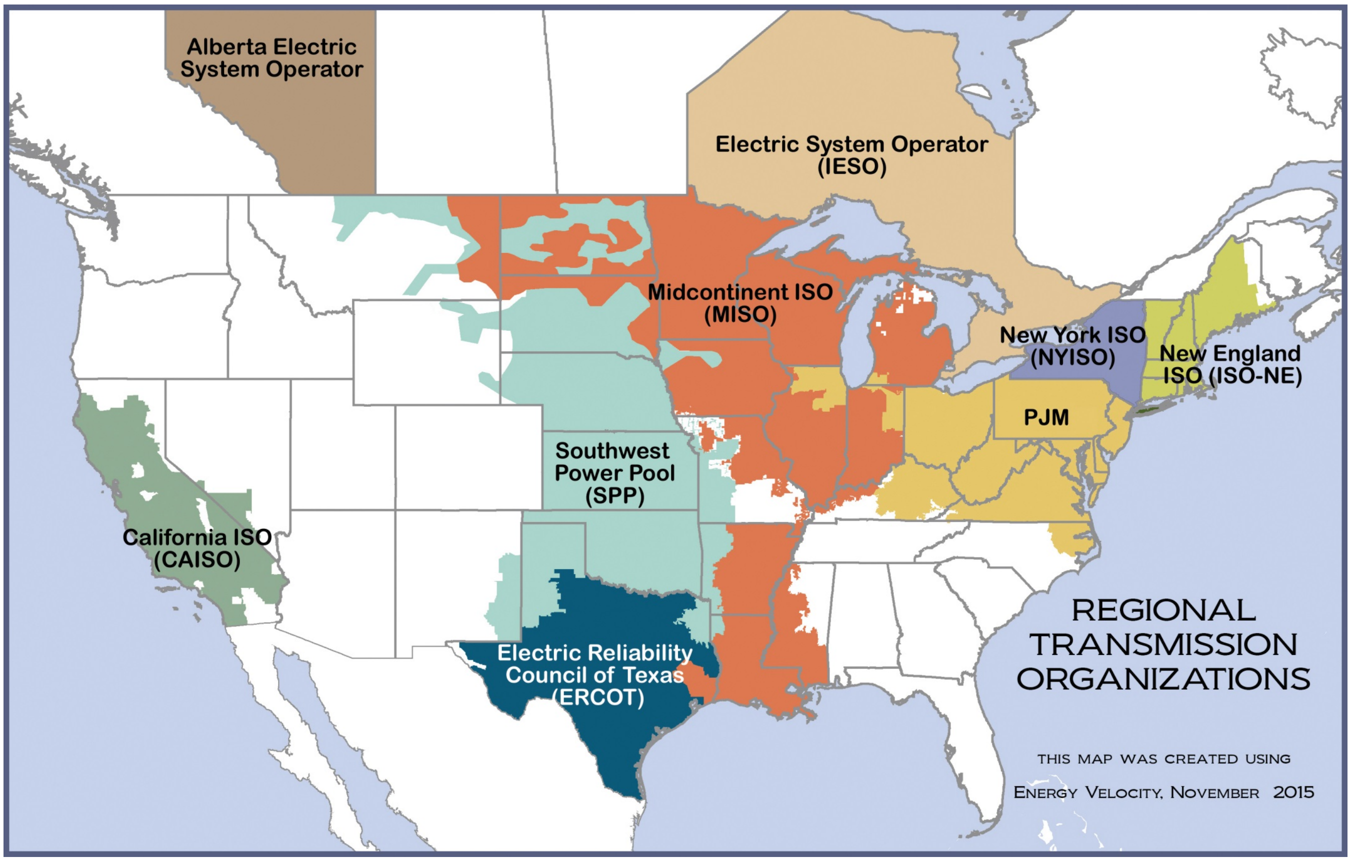


TABLE 6.4

Proposed Plants, by RTO Region

RTO	Capacity (MW)	Share
Non RTO	84,017.89	46.61%
PJM ISO	26,730.45	14.83%
California ISO	15,618.19	8.66%
SPP	14,955.93	8.30%
Midcontinent ISO	14,119.90	7.83%
ERCOT ISO	11,284.40	6.26%
New York ISO	8,059.43	4.47%
New England ISO	5,474.97	3.04%
Total	**180,261.14**	**100.00%**


Alberta Electric System Operator
Electric System Operator (IESO)
Midcontinent ISO (MISO)
New York ISO (NYISO)
New England ISO (ISO-NE)
PJM
Southwest Power Pool (SPP)
California ISO (CAISO)
Electric Reliability Council of Texas (ERCOT)
REGIONAL TRANSMISSION ORGANIZATIONS
THIS MAP WAS CREATED USING
ENERGY VELOCITY, NOVEMBER 2015

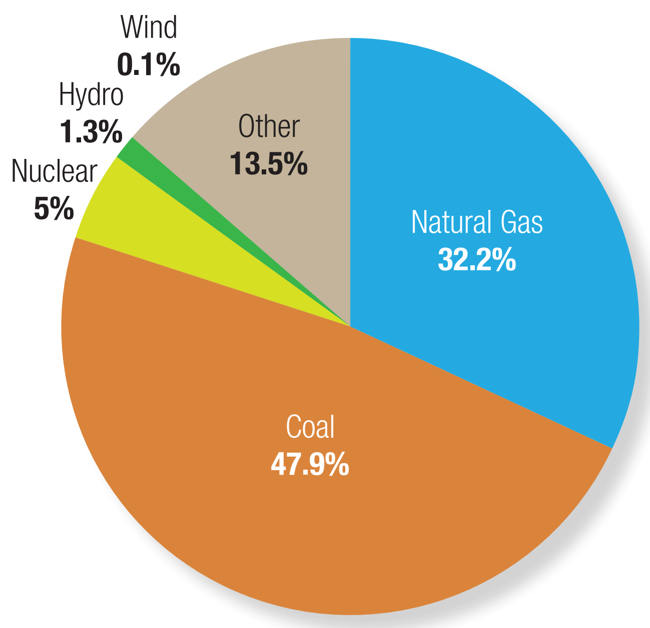
Section 7
Generating Capacity: Retirements and Cancellations

Tables 7.1 and 7.2 show generation capacity retirements by fuel type between 2008 and 2015, when just over 89,500 MW of capacity was retired. Over 80 percent of this retired capacity was natural gas or coal, and 11 percent was oil. More than 84 percent of the retired natural gas capacity used steam turbines.

TABLE 7.1

Retired Plants by Fuel Type, 2008-2015

Primary Fuel Type	Capacity (MW)	Share
Coal	42,851.80	47.9%
Natural Gas	28,778.05	32.2%
Residual Fuel Oil	6,409.50	7.2%
Nuclear	4,457.57	5.0%
Distillate Fuel Oil	3,948.44	4.4%
Hydro	1,123.25	1.3%
Kerosene	336.30	0.4%
Petroleum Coke	323.50	0.4%
Wood/Wood Waste Solids	190.80	0.2%
Wood Waste Liquids	187.30	0.2%
Landfill Gas	172.10	0.2%
Blast Furnace Gas	171.20	0.2%
Wind	133.60	0.1%
Waste Oil and Other Oil	103.00	0.1%
Other	94.30	0.1%
Geothermal	54.20	0.1%
Waste	49.20	0.1%
Other Gas	37.50	0.0%
Purchased Steam	37.00	0.0%
Jet Fuel	17.60	0.0%
Biomass Liquids	15.80	0.0%
Biomass Gases	9.70	0.0%
Solar	9.50	0.0%
Total	**89,511.22**	**100.0%**



Over 18,000 MW of capacity was retired in 2015 alone, of which coal accounted for almost 80 percent.

Table 7.3 reflects planned retirements that have been publicly announced.

TABLE 7.2

Retired Plants by Fuel Type, 2015

Primary Fuel Type	Capacity (MW)	Share
Coal	14,346.50	79.3%
Natural Gas	2,461.75	13.6%
Distillate Fuel Oil	657.80	3.6%
Kerosene	336.30	1.9%
Residual Fuel Oil	143.70	0.8%
Hydro	138.80	0.8%
Landfill Gas	12.80	0.1%
Jet Fuel	1.40	0.0%
Total	**18,099.05**	**100.0%**

Approximately 45,000 MW of current operating capacity is scheduled to retire by 2020, nearly half of which is coal. Almost all planned natural gas retirements are powered by steam or gas combustion turbines.

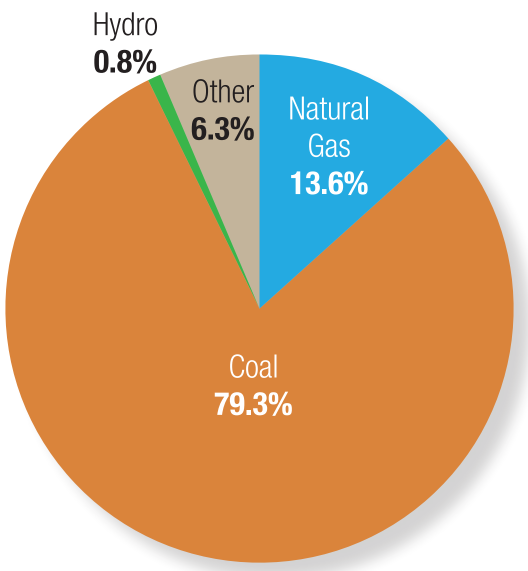
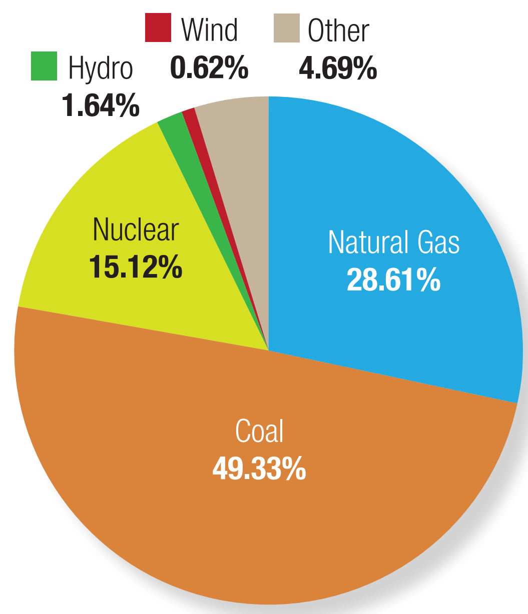


TABLE 7.3

Planned Retirements to 2020, by Fuel Type

Primary Fuel Type	Capacity (MW)	Share
Coal	22,079.20	49.33%
Natural Gas	12,803.20	28.61%
Nuclear	6,765.13	15.12%
Residual Fuel Oil	1,321.50	2.95%
Hydro	732.60	1.64%
Distillate Fuel Oil	573.80	1.28%
Wind	279.35	0.62%
Wood/Wood Waste Solids	97.10	0.22%
Kerosene	72.60	0.16%
Landfill Gas	26.90	0.06%
Biomass Gases	4.90	0.01%
Total	**44,756.28**	**100.00%**



Over 28,000 MW of planned capacity additions were canceled in 2015, or just over double the amount of capacity added to the grid. Wind and solar constituted 84 percent of this canceled capacity.

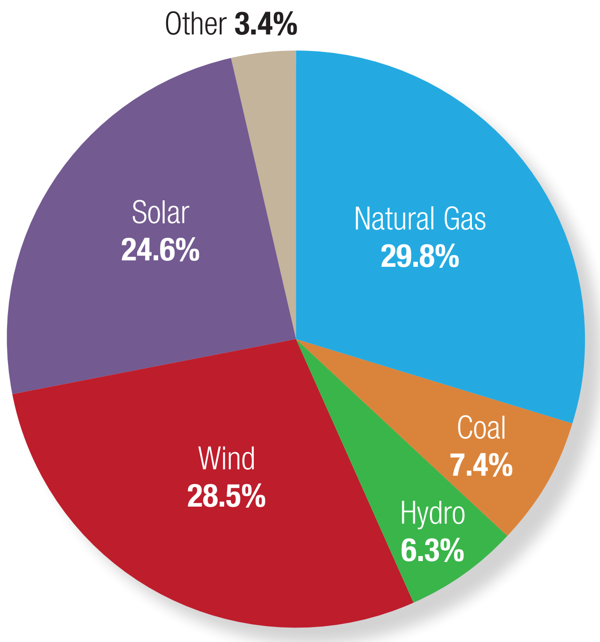


TABLE 7.4

Plant Cancellations, 2015

Primary Fuel Type	Capacity (MW)	Share
Natural Gas	8,411.82	29.8%
Wind	8,024.68	28.5%
Solar	6,941.79	24.6%
Coal	2,099.00	7.4%
Hydro	1,790.16	6.3%
Geothermal	422.00	1.5%
Waste	159.00	0.6%
Wood/Wood Waste Solids	131.55	0.5%
Biomass Solids	73.83	0.3%
Other	72.08	0.3%
Landfill Gas	23.10	0.1%
Distillate Fuel Oil	22.50	0.1%
Other Gas	17.00	0.1%
Biomass Gases	15.40	0.1%
Waste Heat	1.80	0.0%
Total	**28,205.71**	**100.0%**

Since 2008, over 374,000 MW of planned capacity additions were ultimately canceled, more than double the amount that was actually added. Wind represents 28 percent of this canceled capacity. Nearly equal shares of coal, natural gas, hydro, and solar were also canceled during this time.

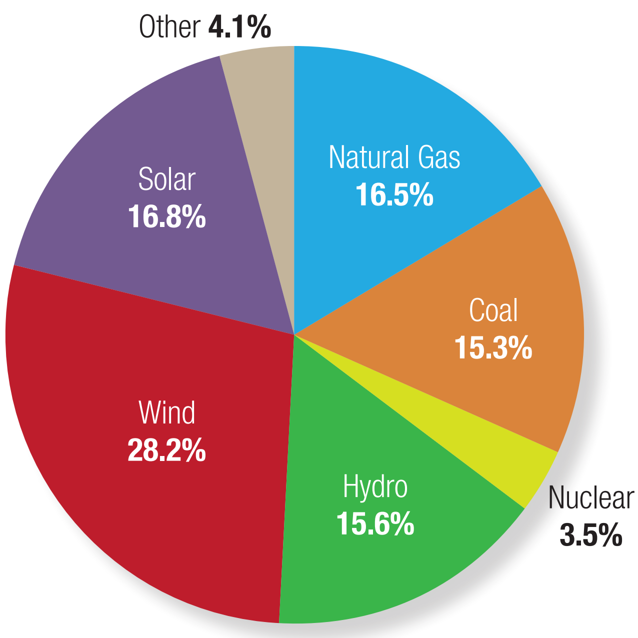


TABLE 7.5

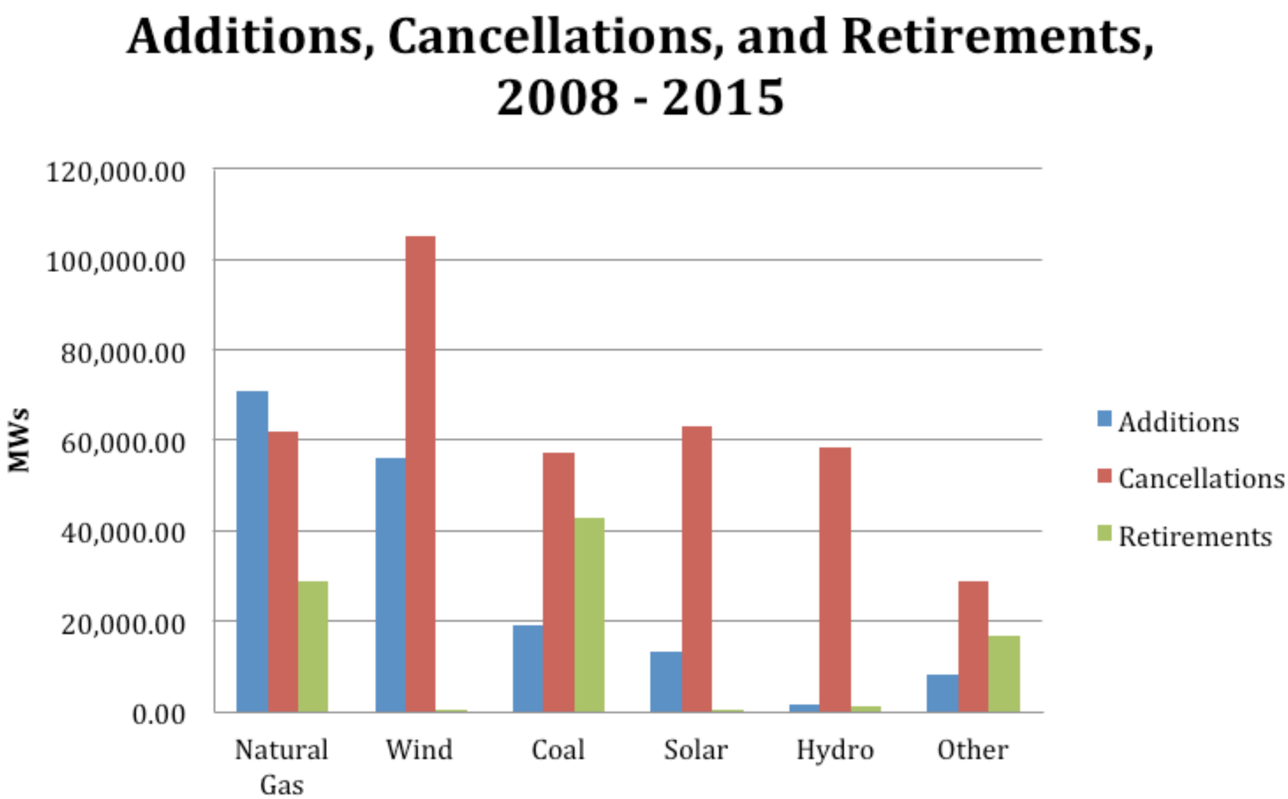
Plant Cancellations, 2008-2015

Primary Fuel Type	Capacity (MW)	Share
Wind	105,369.64	28.2%
Solar	62,851.51	16.8%
Natural Gas	61,712.78	16.5%
Hydro	58,380.58	15.6%
Coal	57,287.50	15.3%
Nuclear	12,930.00	3.5%
Petroleum Coke	4,980.20	1.3%
Wood/Wood Waste Solids	3,413.92	0.9%
Geothermal	2,136.00	0.6%
Biomass Solids	1,243.88	0.3%
Other Gas	848.00	0.2%
Waste	845.30	0.2%
Other	716.28	0.2%
Biomass Gases	485.00	0.1%
Landfill Gas	387.82	0.1%
Agriculture Byproduct	280.32	0.1%
Waste Heat	127.60	0.0%
Blast Furnace Gas	100.00	0.0%
Biomass Liquids	77.60	0.0%
Kerosene	49.20	0.0%
Distillate Fuel Oil	44.48	0.0%
Wood Waste Liquids	3.80	0.0%
Total	**374,271.39**	**100.0%**

Figure 7.1 shows additions, cancellations, and retirements from 2008 to 2015. Natural gas is the only resource for which additions outnumber cancellations. For all other resources, far more capacity was cancelled than was added.

FIGURE 7.1

Additions, Cancellations, and Retirements, 2008-2015



Section 8
Cost and Capacity Factors

As domestic generating capacity changes, it is worthwhile to look at the cost to construct new sources as well as to consider capacity factors. Costs to construct new generation vary considerably by fuel type, with natural gas generally cheaper on a per-MW basis than almost all forms of generation, and renewable forms of generation being more expensive.

Table 8.1 shows the average construction cost per MW of operating capacity that has come online since 2010. Cost data are available only for plants which have publicly released such data. This table also includes costs only for those fuel types with at least 250 MW of reported capacity, and includes only expansion and new builds.

Table 8.2 shows average construction costs for all planned new capacity. Once again this includes cost data only for those planned new plants for which such data are available, and includes fuel types for which there are at least 250 MW of planned capacity. All costs are in 2015 dollars. This only includes cost estimates for expansions and new builds.

TABLE 8.1

Cost per MW for Major Fuel Types for New Capacity, 2010-2015

Fuel Type	Cost per MW (000s)
Coal	$2,134
Distillate Fuel Oil	$1,153
Hydro	$3,736
Landfill Gas	$3,276
Natural Gas	$947
Other Gas	$7,353
Petroleum Coke	$1,421
Solar	$4,382
Wind	$2,105
Wood/Wood Waste Solids	$4,440

TABLE 8.2

Cost per MW for Major Fuel Types for Planned Capacity

Fuel Type	Cost per MW (000s)
Blast Furnace Gas	$4,000
Coal	$3,483
Geothermal	$4,017
Hydro	$2,692
Natural Gas	$1,013
Nuclear	$4,201
Petroleum Coke	$13,193
Solar	$3,684
Wind	$1,795
Wood/Wood Waste Solids	$17,316

Table 8.3 shows capacity factors for all fuel types. Capacity factors are a measure of how much of a generating plant's maximum generation potential is being utilized throughout the year.

TABLE 8.3

National Capacity Factor Totals, 2015

Primary Fuel	Capacity (MW)	Net Generation (MWh)	Capacity factor
Natural Gas	475,313.05	1,124,116,671.00	27.00%
Coal	333,601.58	1,587,578,118.00	54.33%
Nuclear	107,617.51	797,165,982.00	84.56%
Hydro	84,123.53	258,434,239.00	35.07%
Wind	63,183.77	181,076,401.00	32.72%
Distillate Fuel Oil	25,529.52	3,209,702.00	1.44%
Residual Fuel Oil	10,255.70	7,391,476.00	8.23%
Solar	7,840.71	16,143,428.00	23.50%
Wood Waste Liquids	5,890.24	28,822,553.00	55.86%
Wood/Wood Waste Solids	4,376.73	19,327,950.00	50.41%
Geothermal	3,811.46	16,034,781.00	48.03%
Waste	2,679.10	14,255,299.00	60.74%
Petroleum Coke	2,441.60	9,315,089.00	43.55%
Kerosene	2,211.98	121,472.00	0.63%
Landfill Gas	2,166.59	10,727,077.00	56.52%
Other Gas	1,558.90	9,399,467.00	68.83%
Blast Furnace Gas	831.10	2,883,231.00	39.60%
Purchased Steam	584.40	1,343,547.00	26.24%
Waste Heat	570.53	2,390,204.00	47.82%
Biomass Gases	528.60	1,511,981.00	32.65%
Jet Fuel	469.84	318,875.00	7.75%
Agriculture Byproducts	322.60	881,040.00	31.18%
Other	320.80	1,250,784.00	44.51%
Waste Oil and Other Oil	91.30	350,599.00	43.84%
Propane	1.63	487.00	3.41%
Total	**1,136,322.78**	**4,094,050,453.00**	**41.13%**

For some fuel types, capacity factor is impacted by the prime mover, or the engine type. For example, though the capacity factor for all natural gas plants is approximately 27 percent, the capacity factor for combined cycle plants is much higher at 42 percent. Meanwhile, capacity factors for natural gas plants fired by combustion turbines is barely over 7 percent, and is just over 10 percent for steam turbines. Most new natural gas generation is combined cycle.

Size also has an impact on certain fuels. Solar plants less than 10 MW in size have capacity factors under 20 percent, but capacity factors generally increase as solar plant capacities increase in size.

Capacity factors can be used to adjust construction costs. If capacity factors are incorporated into cost formulas, it changes the costs for most fuel types. Tables 8.4 and 8.5 incorporate capacity factors into costs for newly operational and planned major fuel types. Because natural gas capacity factors differ significantly based on prime mover type, an additional assessment of adjusted costs based on prime mover for natural gas capacity is incorporated into the tables. Note that approximately 90 percent of all planned natural gas capacity is combined cycle.

TABLE 8.4

Adjusted Cost per MW for New Capacity, 2010-2015

Fuel Type	Cost per MW (000s)	Capacity Factor	Adjusted Cost per MW (000s)
Coal	$2,134	54%	$3,952
Hydro	$3,736	35%	$10,675
Natural Gas	$947	27%	$3,508
Solar	$4,382	26%	$16,855
Wind	$2,105	33%	$6,379
Natural Gas by Prime Mover			
Combined Cycle	$955	42%	$2,273
Combustion Gas Turbine	$854	7%	$12,196
Internal Combustion Engine	$1,496	12%	$12,464

TABLE 8.5

Adjusted Cost per MW for Planned Capacity

Fuel Type	**Cost per MW (000s)**	**Capacity Factor**	**Adjusted Cost per MW (000s)**
Coal	$3,483	54.0%	$6,450
Hydro	$2,692	35.0%	$7,691
Natural Gas	$1,013	27.0%	$3,753
Nuclear	$4,201	85.0%	$4,942
Solar	$3,684	26.0%	$14,168
Wind	$1,795	33.0%	$5,440
Natural Gas by Prime Mover			
Combined Cycle	$991	42%	$2,2359
Combustion Gas Turbine	$1,114	7%	$15,909
Internal Combustion Engine	$1,215	12%	$10,124

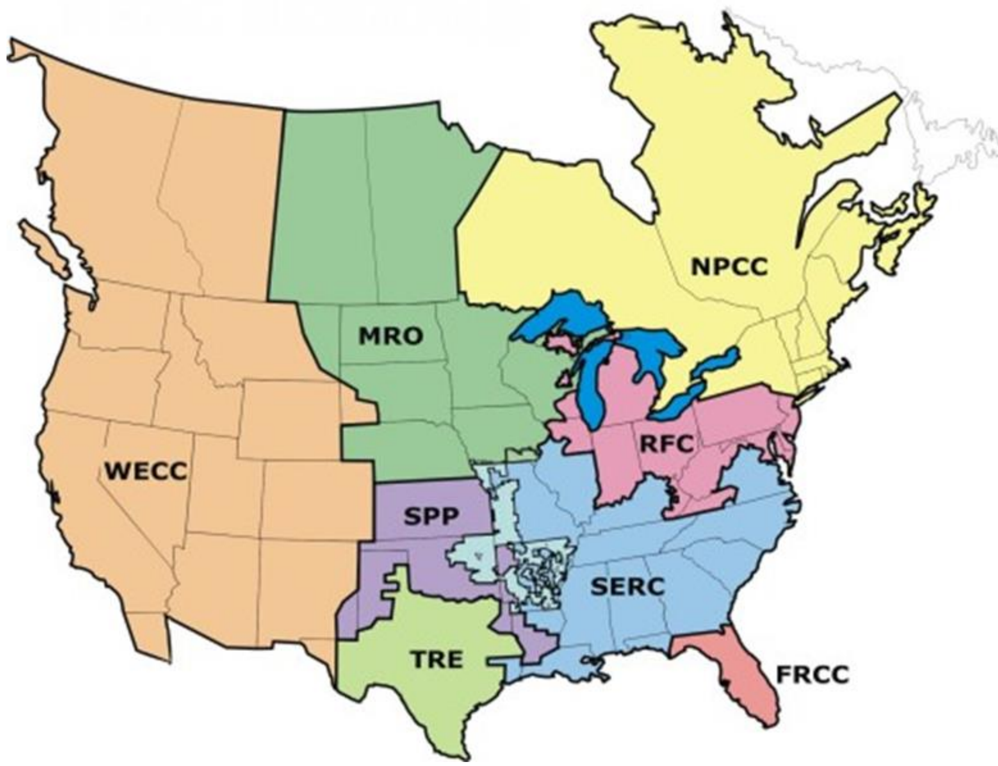
Though some resources may have less expensive construction costs than others, utilization rates as represented by capacity factors need to be taken into account. Absent large-scale batteries, renewable resources such as wind and solar can provide power only at select times of the day and under certain conditions, while nuclear power plants are able to operate at full capacity nearly all the time. Newer combined cycle natural gas plants also operate at much higher efficiency levels. These baseload options thus do not require backup forms of generation. That means the total costs to deploy these resources may be less on a megawatt-by-megawatt basis than renewable generation. Other circumstances unique to each location will also impact capacity factors and thus overall costs. When one additionally factors the continued low cost of natural gas, it is likely that it will continue to be the leading fuel choice for new generation for the immediate future.

Section 9
Conclusion

A pattern has emerged over the past several years in terms of new generating capacity development. Natural gas, followed by wind, is the major sources of new generation, though solar deployment continues to expand as well. Nearly half of all new capacity is fueled by natural gas, and this is a trend that is likely to continue for the immediate future.

The data show that the spate of new generation is just barely keeping ahead of retirements. Though approximately twice as much utility-scale generation has been added to the grid since 2008 as has been retired, retirements actually outpaced capacity additions in 2015. The amount of capacity that is already under construction or permitted roughly doubles the amount of announced retirements scheduled through 2020, but that is based on a conservative estimate of announced retirements. The Environmental Protection Agency's Clean Power Plan (CPP) could lead to many more retirements, especially of coal capacity. Considering that a majority of the nation's coal-fired capacity is forty years of age or older, this could lead to large-scale retirements. Factoring in relative costs, it is likely that this capacity would be replaced by natural gas as well, leading to a greater reliance on this particular fuel.

Appendix
NERC Regions



This report uses regions defined by the North American Electric Reliability Council:

ASCC - Alaska Systems Coordinating Council (not shown on map)
FRCC – Florida Reliability Coordinating Council
HCC – Hawaii Coordinating Council (not shown on map)
NPCC - Northeast Power Coordinating Council
MRO – Midwest Reliability Organization
RFC – Reliability First Corporation
SERC - Southeastern Electric Reliability Council
SPP – Southwest Power Pool
TRE – Texas Reliability Entity*
WECC - Western Electricity Coordinating Council

** The Independent System Operator that operates the electric grid for nearly all of the state of Texas is the Electric Reliability Council of Texas (ERCOT), and is the name used for this region in the report. The Texas Reliability Entity (TRE) monitors and enforces compliance with reliability standards for NERC.*

February 10, 2014

The Honorable Cheryl A. LaFleur, Acting Chairman
The Honorable Philip D. Moeller, Commissioner
The Honorable John R. Norris, Commissioner
The Honorable Tony Clark, Commissioner

Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: *Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators,* Docket No. AD13-7-000

Dear Acting Chairman and Commissioners:

The undersigned entities comprise a broad and diverse *ad hoc* group of publicly and cooperatively owned electric utilities, national consumer and low-income organizations, state public utility commissions, state consumer advocates, investor-owned utilities, industrial customers, and independent power producers. While we represent a range of diverse and often diverging interests, we are writing to emphasize our consensus on certain of the core points made in many of the comments filed in the above-noted docket on January 8, 2014:

- <u>Capacity Is Not Fungible</u>. Not all MWs of capacity are created equal. Load serving entities (LSEs), states, and local regulatory bodies may have excellent policy reasons for preferring to assemble a diverse portfolio of generation and demand-side resources to serve retail electric needs.

- <u>Many Policy Considerations Affect Resource Portfolio Choices</u>. The policy concerns that might lead LSEs, 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 policy makers should respect and honor them. Market rules that Regional Transmission Organizations (RTOs) impose to protect prices under administrative capacity procurement constructs should not erect barriers to meeting such policy goals.

- <u>Long-term Contracts Support New Resources and Should Be Encouraged</u>. Capacity surpluses can no longer be taken for granted; new resources will have to be developed to comply with new 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. RTO market rules that effectively penalize long-term contracting and self-supply should be reformed.

- The Commission Must Consider Rate Impacts on Retail Electric Consumers. Market participants wishing to protect their economic interests dominate Commission adjudicative dockets and RTO stakeholder processes. In these fora, the interests of retail consumers and those charged with protecting them are often lost. It is up to the Commission to ensure that capacity procurement constructs and the associated market rules work for the retail electric consumers that ultimately pay the bills, and not just for those market participants with the most resources to devote to the administrative process.

The undersigned entities respectfully request the Commission to take further actions in relevant adjudicative and rulemaking dockets to ensure that these principles are honored in RTO capacity procurement mechanisms. We stand ready to work with the Commission to help make this happen.

Respectfully submitted,

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ENSURING ADEQUATE POWER SUPPLIES FOR TOMORROW'S ELECTRICITY NEEDS

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Electric Markets Research Foundation

Christensen Associates Energy Consulting conducted this study for the Electric Markets Research Foundation (EMRF). EMRF was established in 2012 as a mechanism to fund credible expert research on the experience in the United States with alternative electric utility market structures – those broadly characterized as the traditional regulated model where utilities have an obligation to serve all customers in a defined service area and in return receive the opportunity to earn a fair return on investments, and the centralized market model where generation is bid in to a central market to set prices and customers generally have a choice of electric supplier.

During the first few years of restructured markets, numerous studies were done looking at how these two types of electric markets were operating and the results were mixed. But since those early studies, limited research has been done regarding how centralized markets and traditionally regulated utilities have fared. The Electric Markets Research Foundation has been formed to fund studies by academics and other experts on electric market issues of critical importance.

Christensen Associates Energy Consulting

CA Energy Consulting is a wholly owned subsidiary of Laurits R. Christensen Associates, Inc., whose multi-disciplinary team of economists, engineers, and market research specialists has been serving the electric power industry (as well as other industries) since 1976. CA Energy Consulting's focus on energy markets covers a broad range of technical and regulatory policy issues concerning wholesale and retail electricity market restructuring, market design, power supply, asset evaluation, transmission pricing, market power, retail and wholesale rate design, and customer response to price signals.

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The Resource Adequacy Challenge

The Electric Markets Research Foundation (Foundation) critically examines key issues facing the country's electricity sector arising from industry restructuring that has taken place over the past two decades. The Foundation commissioned Christensen Associates Energy Consulting to examine the ability of the U.S. electric power industry to build and maintain sufficient electric generating capacity to meet the country's present and future needs. While many regions of the country have undertaken restructuring of both retail and wholesale electricity markets, others have not, so that the U.S. electricity sector now serves consumers under two distinct market models. These models have different impacts upon the development of power facilities and the production and delivery of power. One market model relies on competitive bidding to establish market prices for wholesale power delivered to end-use customers by retail suppliers who may or may not own generation, transmission, and distribution facilities. Regional transmission organizations (RTOs) or independent system operators (ISOs) operate the competitive wholesale markets in restructured market regions.

The other market model relies on traditional regulation of vertically integrated utilities that provide generation, transmission, and distribution services to end-use customers at prices approved by state regulatory commissions. Within the restructured market regions, many but not all states have adopted retail competition, in which multiple retail suppliers of electric energy and related services compete to serve end-users. The first report published by the Foundation, entitled *Evolution of the Electric Industry Structure in the U.S. and Resulting Issues,* discusses in significant detail the historical transition to today's dual market system and the industry's current status.[1]

Whether the electricity sector is able to continue to develop and maintain sufficient resources to "keep the lights on" now and in the future, referred to as resource adequacy, has emerged over the past several years as perhaps the greatest challenge facing the electric power industry. Potentially serious resource adequacy problems were laid bare by the recent "polar vortex" of January and February 2014, when record cold temperatures across most of the eastern and Midwestern United States had the industry scrambling to keep up with the demand for electricity. While the industry managed to avoid blackouts, a general consensus has emerged that the industry came perilously close to exceeding its limits to maintain electric system

[1] Navigant Consulting, Inc., *Evolution of the Electric Industry Structure in the U.S. and Resulting Issues*, prepared for Electric Markets Research Foundation, October 12, 2013, available at www.emrf.net.

reliability. Maintaining reliability during this period meant that many electricity consumers in some parts of the country paid unprecedented high prices for electricity. The nation's ability to cope with a future "polar vortex" will be compromised by the slated retirements over the next few years of many of the generating plants called upon to keep the lights on during this last "polar vortex." American Electric Power Company (AEP) CEO Nicholas Akins, in testimony before the Senate Energy and Natural resources Committee in April, pointed to January's deep freeze as a warning signal:

> A month ago, I made headlines when I said 89 percent of the generation that AEP will be retiring in 2015 was called upon to meet electricity demand in January. That is a fact… The weather events experienced this winter provided an early warning about serious issues with electric supply and reliability… This country did not just dodge a bullet -- we dodged a cannon ball.[2]

Akins told Congress that the problem needs to be fixed quickly. He asserted that the capacity markets in restructured market regions are "not functioning as intended," and are failing to attract investment capital and to send price signals to retain existing generation in order to maintain a mix of energy resources necessary to ensure grid reliability. According to Akins, "[t]he [restructured] competitive wholesale markets are not currently providing the structure necessary to maintain that reliability and do not currently provide the proper economic signals to foster new power plant investment for the future."[3]

Instead the electric power industry has become increasingly reliant on natural gas, particularly in the restructured wholesale markets. Recent downward trends in wholesale market prices and compliance with environmental regulations are increasingly rendering base load (coal and nuclear) power sources uneconomic. For example, AEP is slated to retire more than 6,500 megawatts of coal-fired generation – most of it by mid-2015 – and does not plan to add new capacity in the near term.

Reliability is not the only issue. Shortages of power during the polar vortex created significant spikes in the price of wholesale power, which has quickly morphed into a political issue. PPL Corporation, a utility serving customers in central Pennsylvania, saw wholesale (spot market) prices briefly exceed $2,000 per megawatt hour compared to $40 per megawatt hour on a normal day.[4] In Texas, where the grid is managed by the Electric Reliability Council of Texas (ERCOT), prices reached wholesale market price cap of $5,000 per megawatt hour for the first

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[2] *Testimony of Nicholas K. Akins*, Chairman, President and Chief Executive Officer, American Electric Power, Senate Energy and Natural Resources Committee Hearing on "Keeping the Lights On - Are We Doing Enough to Ensure the Reliability and Security of the U.S. Electric Grid?", April 10, 2014, pp. 2-4.

[3] *Id.*, p. 5.

[4] G.J. Millman, "PPL's Risk Management Tested by Polar Vortex," *Wall Street Journal*, April 17, 2014, obtained at http://blogs.wsj.com/riskandcompliance/2014/04/17/ppls-risk-management-tested-by-polar-vortex/.

time ever on January 6^{th}, partly due to plant outages.[5] Few retail customers experienced these high prices at the time because retail electricity rates typically do not fluctuate with changes in wholesale spot market prices. But those electricity customers whose bills *do* reflect hourly wholesale prices, including many in New York and New England, experienced significant price shock. For example, based on an estimated 27% jump in wholesale electricity prices in January, the New York Public Service Commission authorized National Grid serving northern New York State to recover January's higher wholesale power costs in retail rates over a four month period. U.S. Senator Charles Schumer has called for an FTC investigation into these price spikes in northern New York.

Most of the concerns regarding resource adequacy have arisen in the context of restructured wholesale and retail electric markets. The restructured markets are still trying to prove the workability of their model for assuring resource adequacy. By contrast, capacity reserves have been successfully maintained in almost all regions that have not restructured and that continue to rely on franchised electric utilities that take direct responsibility for resource adequacy under an obligation to serve. The success of traditionally regulated electric markets to maintain resource adequacy has not been achieved without controversy, however, as questions have sometimes arisen about how those reserve requirements were satisfied and at what cost. Nevertheless, resource adequacy has not been seen as a major issue in traditionally regulated markets in the past.

Additional Concerns in Restructured Markets

While the polar vortex provided a warning signal to the nation, it is not just extreme weather and attendant wholesale power price spikes that is creating concern about resource adequacy in the restructured markets. Additional concerns that have arisen in restructured markets include the following:

- Reserve margins have declined in almost all regions of the country over the past decade. However, the decline in restructured market regions has been more pronounced than in other regions, and has become the center of increasing concern, highlighted by the recent polar vortex experience. Furthermore, projected capacity retirements – primarily due to environmental restrictions - exceed planned additions for the foreseeable future.
- Low average wholesale market electricity prices in restructured markets in recent years have made it more difficult for owners to recover plant operating costs and have thereby induced the retirement of two carbon-free nuclear power plants. Additional nuclear plants are in danger of closing for similar reasons.

[5] K. Kelly-Detwiler, "Volatility In Early January Power Markets: The Vexing Polar Vortex," January 16, 2014, obtained at http://www.forbes.com/sites/peterdetwiler/2014/01/16/volatility-in-early-january-power-markets-the-vexing-polar-vortex/.

- With natural gas as the preferred fuel source for the majority of newly installed or planned generation capacity in restructured markets, the polar vortex has also focused attention on long-term gas availability and pricing, including the availability of firm gas pipeline transportation. Is there over-reliance on natural gas? What are the economic security and consumer price volatility concerns that result from heavy reliance on natural gas?
- Increased reliance on intermittent resources that are not always available when needed, such as solar and wind, raise additional concerns for maintaining resource adequacy.
- Subsidies for particular generation technologies, such as the production tax credits for wind energy, tend to distort competitive market outcomes.
- A host of public policies interfere with the operation of restructured electricity markets. Consequently, these markets provide only limited support for investment in generation and other resources.
    - The restructured markets cap prices in order to limit consumers' exposure to price volatility. With prices capped, the market-clearing price paid to resources under capacity shortage conditions cannot reach levels high enough to encourage the provision of sufficient additional resources or induce sufficient load reductions. .
    - For the years 2005 through 2012, the RTOs' analyses of revenue sufficiency indicate that net revenues were generally insufficient to allow recovery of the levelized capital costs of generation investment. Thus, on a levelized basis, the RTOs' markets did not present an attractive enough opportunity to encourage sufficient investment in needed generation.
    - Some RTOs have implemented a market-like approach to capacity adequacy through the institution of centralized capacity markets that provide cost recovery assurance at most three years into the future. This short timeframe gives a very limited incentive for investments in capital-intensive generators with lives of thirty years or more.
    - Restructured markets do not provide market participants with mechanisms to arrange the long-term price hedges that can be critical to investment in long-term capacity.
    - Restructured market rules have been subject to frequent revision, thus creating uncertainty about their durability and adding to investment uncertainty.

  The consequences of these realities have been supplier bankruptcies and disincentives for arranging long-term supplies.

There is reason to be concerned that, as a nation, we are paying insufficient attention to the issue of resource adequacy, particularly in restructured markets. While the obligation to serve coupled with integrated resource planning have enabled traditionally regulated markets to maintain sufficient planning reserves to meet current and future needs, levels of planning reserves in restructured markets have by and large been left to market forces. As these restructured markets have found that market prices have not always provided sufficient incentives to maintain required levels of reserves, they have attempted numerous market adjustments, including the establishment of separate capacity markets, to add additional resources. It does not appear that these efforts have been successful to date.

A key finding of this report is that problems of restructured markets with securing adequate resources stems from their seeking a market solution to a problem for which there is not a market solution within existing political and institutional frameworks. Because of the shortcomings of market-based approaches, non-market (i.e., regulatory) mechanisms must be part of the overall approach to ensuring long-term resource adequacy. Long-term contracts and self-build options for load-serving entities (LSEs) must be encouraged to ensure an adequate resource mix.

Traditional Versus Restructured Markets

About a third of the U.S. population obtains electric power service based on traditional institutional arrangements. Under these arrangements, power is provided to consumers by vertically integrated utilities that own generation, have exclusive retail franchises, and trade wholesale power through bilateral contracts. Retail prices are regulated by state public service commissions.

About two-thirds of the U.S. population obtains electricity through electric markets that have been restructured at the wholesale level. In these markets, generating capacity owned by utilities and independent third parties compete to sell generation into a centralized wholesale market as well through bilateral trades, with the lowest-cost resources that can reliably serve demand being chosen on a real-time basis. In some states within these restructured markets, retail customers may choose their electric supplier among competing entities that may be utilities or third-party competitive retail suppliers.

Both traditional and restructured markets require mechanisms for assuring resource adequacy.

In all markets other than Texas, LSEs have an obligation to procure capacity that is sufficient to serve their own retail load and cover reserves.[6] In traditional markets, utilities build and own their own generating units or do so jointly with other utilities, develop long-term purchase arrangements with independent power producers, or procure short- and long-term resources under negotiated bilateral power purchase agreements with entities that have surplus resources. Utilities in these markets recover the costs of procuring these resources by charging rates that are determined by their costs of service.

In restructured markets, utilities sometimes procure capacity resources in much the same fashion as in traditionally regulated regions. However, in restructured markets, utilities are

[6] In Texas, retail energy providers (REPs) serve retail electric consumers without bearing a requirement to secure capacity sufficient to meet their load.

typically either allowed – or in some cases required – to trade through centralized short-term capacity markets operated by Regional Transmission Operators (RTOs). In states with retail access, regulators have often discouraged retail LSEs from owning their own generating resources, sometimes even barring LSEs from engaging in long-term contracts to hedge against short-term price fluctuations.

While traditionally regulated electricity markets have regulatory issues, such as sometimes contentious proceedings to determine whether investments have been prudently incurred, these markets continue to meet resource adequacy requirements under the supervision of state regulators. The restructured markets, by contrast, are still trying to prove the workability of their model for assuring resource adequacy. Thus far, the RTOs have maintained adequate capacity. Nonetheless, some RTOs may or will soon be operating with historically low planning reserves under peak period conditions, particularly given planned retirements. It is unclear to what extent centralized capacity markets will assure reserve margins in restructured RTO markets, especially because the restructured states continue to play a significant role in determining capacity requirements for LSEs and mandating investments in renewable resource capacity. And some states are attempting to mandate additional investment in traditional resources outside RTO capacity markets as well.[7]

The current debate on resource adequacy arises primarily from questions about how to make the RTOs' resource adequacy models work. The fundamental problem is that the RTOs seek a market solution for a problem that does not have a market solution because a suite of public policies require that capacity resources meet several non-market goals. These non-market goals include:

- Electricity is vital to the national economy and shortages and price spikes are not tolerated by policymakers, regulators, and customers.
- To protect customers from excessive price volatility, prices offered by generators in restructured markets are capped below levels that are needed to clear the market during peak load periods when capacity is scarce. Consequently, generators that serve load at peak are not able to obtain revenues sufficient to cover all of their costs, causing a "missing money" problem that dampens incentives for investment in new capacity.
- The portfolio of capacity resources must include certain types of preferred resources – notably renewable resources and demand-side resources – that may be costly relative to conventional resources.

[7] See New Jersey Board of Public Utilities and New Jersey Division of Rate Counsel, Petitioners, in Case No. 11-4245 v. Federal Energy Regulatory Commission, Respondent; and Maryland Public Service Commission, Petitioner, in Case No. 11-4405 v. Federal Energy Regulatory Commission, Respondent. The United States Court of Appeals for the 3rd Circuit in February 2014 denied requests of both New Jersey and Maryland commissions, as well as others who joined in the appeal for review of FERC's earlier order denying rehearing of its 2011 orders pertaining to the PJM capacity market that eliminated the exemption from capacity market mitigation rules for resources built pursuant to a state mandate.

- Different customers have different willingness to pay for different levels of bulk system reliability, but only one level of reliability can be maintained. Thus, reliability must be maintained at levels that exceed many customers' willingness to pay for reliability.

Because of these and other problems, the RTOs are continually reforming their capacity markets, sometimes in major ways, often through contentious proceedings, as they search for a market solution that cannot exist. Some RTOs have attempted to implement a market solution through the institution of short-term centralized capacity markets; but these markets have the key deficiency of going at most three years into the future, which cannot provide incentives for long-term capital-intensive generation investments with lives of thirty years or more.

Resource Mix

The mix of capacity resources can have major impacts on power system reliability, for several reasons. First, supplies of particular resources can become constrained due to weather conditions, transportation bottlenecks, or production problems; so over-reliance upon a single resource technology can have adverse reliability or cost impacts. Second, demand-side capacity resources are an innovation that is not entirely out of the testing stage: in the long run, such resources may or may not prove to be as reliable as traditional supply-side resources. Third, intermittent renewable resources (i.e., wind and solar) pose new challenges for maintaining power system security; and these challenges will grow disproportionately quickly as the market share of these resources grows.

About 23,000 MW of coal-fired generating capacity retired between 2005 and 2013, and another 37,300 MW is expected to retire over the next decade, mostly during the next four years.[8] Many of these retirements are in RTO regions. Meanwhile, in nearly every RTO region, gas-fired generation capacity has at least doubled over the past decade. Wind capacity has increased from almost nothing in 2000 to approximately 6% of total U.S. generating capacity today.

The strong trend throughout the U.S. is toward natural gas capacity, in both restructured and traditionally regulated regions, though traditionally regulated regions have retained more fuel diversity. The differences between restructured and traditionally regulated regions in the change in resource mix seem to rise primarily from state requirements for renewable energy, plus the particular locational advantages of wind and solar resources.

Resource Profitability

To assess the market incentives for capacity investments, several RTOs estimate the net revenues (i.e., profits) that would have been earned in their markets by combustion turbines and combined cycle generators. For each of the years 2005 through 2012, net revenues on an

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[8] SourceWatch, Table 2, http://www.sourcewatch.org/index.php/Coal_plant_retirements.

RTO-wide basis were generally insufficient to cover the levelized costs of these generators, though they were sufficient in ERCOT and New York in a few years and were sufficient in several subregions of the RTOs in some years. Because there was some need for new resource capacity during the boom years of 2005-2007, the insufficiency of net revenues implies a general failure of the RTOs' markets to signal capacity shortages in these years. The failure has led to a general decline in RTO planning reserves in recent years and, particularly in light of the polar vortex experience this past winter, a rising concern that restructured markets may need to do more to address the resource adequacy issue.

To encourage generation investment and delay generation retirements, the RTOs' centralized capacity markets were created to provide resource owners with steady income streams. Nonetheless, their capacity market prices have been volatile over the past decade; so the centralized capacity markets have provided rather volatile income streams that create financial risks for investors in new generating plants.

The investment problem is particularly acute because of the nature of electricity demand. Customer demand has a profile that includes baseline needs during normal weather conditions and usage, and higher peak demands during particularly cold or hot weather (depending on the region). A mix of generating technologies satisfies this range in electricity demand at least cost. The generators that serve demand only during peak load hours may be needed to run only a few days or even a few hours each year. Although such peaker plants have relatively low capital costs, they nonetheless need extremely high prices during those few days or hours to earn revenues sufficient to cover both the variable and fixed costs, including a return on their investment in capacity. Inconsistent with this need, however, the restructured markets have caps on prices generators can offer, thus precluding market prices from reaching levels high enough to provide the needed revenue for the peaker plants during those few hours when they are needed. This "missing money" problem extends beyond peaker plants to all other plant types, including baseload plants. The restructured markets' capacity market mechanisms are intended to make up for the "missing money" and provide sufficient incentives for investment in both base load and peaking generation – so far with limited success.

Key Findings of the Report

The U.S. electric power industry has a 100-year history of providing capacity resources that have been adequate under all but the most extreme conditions. The main contributor to this favorable outcome has been a set of power industry business practices that require resources to exceed peak loads according to certain engineering-based analyses or rules of thumb. These industry practices have been supplemented and strengthened by various state proceedings such as integrated resource planning.

While traditionally regulated electricity markets have issues such as contentious prudence determinations, these markets continue to meet resource adequacy requirements under the supervision of state regulators.

The current debate on resource adequacy arises primarily from questions about how to make the restructured market model work. These questions arise from the following fundamental causes:

- *RTOs' short-term centralized capacity markets do not provide incentives for long-term resource investments*. These markets were designed to improve the short-term commitment and dispatch of power system resources; and for this short-term purpose, they have been very successful. But these RTO markets, being short-term markets, do not and cannot address long-term capacity needs.
- *The political process will not allow peak-period demand pricing that is consistent with a market solution*. Specifically, the RTOs' energy and ancillary services prices are capped by regulators; and on the rare occasions when non-price rationing (e.g., rolling blackouts) occurs due to a capacity shortfall, that rationing does not tend to discriminate between those consumers and retail suppliers who arrange adequate supplies and those who do not.

These fundamental causes imply that the resource adequacy problem does not lend itself to a market solution. The RTOs, as they struggle to fit a square peg into a round hole, must therefore continually reform their capacity markets, sometimes in major ways, always through contentious proceedings, as they search for a market solution that cannot exist under existing political and regulatory frameworks. While a well-functioning market attracts participation because that market provides trades on terms that are comparable to or better than those available through other venues, the restructured markets' centralized capacity markets tend to be mandatory. There are few places in the American economy wherein one can find a free market in which participation is mandatory.

The traditionally regulated markets avoid all the foregoing problems by simply not attempting a market solution, except to the extent that they have competitive bidding procedures to meet identified capacity needs.

There are additional matters that should be, and indeed already are, of great concern to policymakers and all stakeholders in the electric power industry:

- The reliability of some portions of the power system has been challenged by a lack of fuel diversity in new generation development. The cold winter of 2013-2014 (the "polar vortex") and the accompanying gas price spikes and gas delivery issues highlight the perils of over-reliance on any one fuel.
- Gas-electric coordination has become increasingly important as we rely more on natural gas. Questions arise as to whether generation can be counted as firm capacity if it does not have firm gas pipeline transportation contracts. Again, the polar vortex was a demonstration of the possible implications of insufficient firm gas transportation.
- The planned retirement of coal plants (for both economic and environmental reasons), and the actual and potential retirements of nuclear plants for economic reasons, will exacerbate the resource adequacy problem in some RTOs, creating significant reliability concerns.

- There is reasonable concern about the capacity value of demand-side resources. It is risky to over-rely on these resources until they have been thoroughly tested by experience.
- There is reasonable concern about the capacity value of intermittent resources, and about the power system control and security problems raised by their intermittency.

There have been many proposals made to reform capacity markets or to design new methods to ensure resource adequacy in the restructured markets, but most of these proposals assume that tweaks to the restructured market model will be sufficient. A more comprehensive solution is necessary, however. For example, the restructured markets could be designed so that capacity is procured in ways similar to those used in traditional regulated markets: set capacity requirements according to engineering criteria; impose high penalties on those LSEs who fail to meet their requirements; and offer a centralized market for those parties who find the centralized market's terms attractive. Generation could be procured through competitive solicitation as it is done successfully in some traditionally regulated markets as well as in some restructured markets. And RTOs could continue to operate energy markets in the same way as they do today.

Our nation needs to continually strive for better regulatory and market rules that ensure resource adequacy at reasonable cost to consumers and the economy. We recommend that regulators and legislators, at both the federal and state levels, examine the resource adequacy problem in restructured markets closely and develop solutions soon. Because of the significant time that is required to develop new resources, we cannot afford to wait until resource adequacy problems pose a threat to the nation's economy.

ENSURING ADEQUATE POWER SUPPLIES FOR TOMORROW'S ELECTRICITY NEEDS

1. THE RESOURCE ADEQUACY CHALLENGE

The Electric Markets Research Foundation (Foundation) critically examines key issues facing the country's electricity sector arising from industry restructuring that has taken place over the past two decades. The Foundation commissioned Christensen Associates Energy Consulting to examine the ability of the U.S. electric power industry to build and maintain sufficient electric generating capacity to meet the country's present and future needs. While many regions of the country have undertaken restructuring of both retail and wholesale electricity markets, others have not, so that the U.S. electricity sector now serves consumers under two distinct market models. These models have different impacts upon the development of power facilities and the production and delivery of power.

One market model relies on competitive bidding to establish market prices for wholesale power delivered to end-use customers by retail suppliers who may or may not own generation, transmission, and distribution facilities. Restructured market regions utilize regional transmission organizations (RTOs) or independent system operators (ISOs) to operate the competitive wholesale markets.

The other market model relies on traditional regulation of vertically integrated utilities that provide generation, transmission and distribution services to end-use customers at prices approved by state regulatory commissions. Within the restructured market regions, many but not all states have adopted retail competition, in which multiple retail suppliers of electric energy and related services compete to serve end-users. The first report published by the Foundation, entitled *Evolution of the Electric Industry Structure in the U.S. and Resulting Issues,* discusses in significant detail the historical transition to today's dual market system and the industry's current status.[9]

Potentially serious resource adequacy problems were laid bare by the recent "polar vortex" of January and February 2014, when record cold temperatures across most of the eastern and Midwestern United States had the industry scrambling to keep up with the demand for electricity. While the industry managed to avoid blackouts, a general consensus has emerged that the industry came perilously close to exceeding its limits to maintain electric system reliability. While the industry managed to maintain reliability, doing so meant that many electricity consumers in some parts of the country paid unprecedented high prices for electricity during this period. The nation's ability to cope with a future "polar vortex" will be compromised by the slated retirements over the next few years of many of the generating plants called upon to keep the lights during this last "polar vortex." Thus the issue of resource adequacy to meet tomorrow's electricity needs is a critical and timely topic.

[9] Navigant Consulting, Inc. *op cit*.

2. SECURITY, ADEQUACY, AND RELIABILITY

The physics of electric power systems requires that supply and demand be kept in exact balance at all times and that voltages throughout the systems remain within tight limits. Failure to maintain this balance and proper voltages causes deterioration in power quality and can cause blackouts. Reliability problems occur when system operators lack the resources, information, or judgment to maintain the power balance and voltages.

Power system reliability at the transmission level has two major dimensions: security and adequacy. Security depends upon power system operations, particularly including real-time localized deliverability, resource commitment, and dispatch. Adequacy depends upon resource planning and investment, particularly in generation, transmission, and demand-side resources. These two dimensions of reliability are related because security can be maintained only if adequate resources are available to system operators.

Security is a short-term concept that refers to the system's ability to withstand real-time contingencies, particularly outages of major power system facilities (like generators and transmission lines), that would cause demand to exceed supply in some portion(s) of the power system. Without prompt restoration of the power balance either through an increase in supply or controlled but involuntary shedding of firm load, the power system can experience frequency instability, voltage drop, cascading blackouts, and system collapse. Security can change instantaneously due to changes in any of the many factors affecting the power system, including resource availability. Maintenance of security requires that system operators have sufficient resources to be able to respond rapidly to contingencies. A secure power system is one that remains intact and continues to deliver power following some limited amount of equipment failures.

Adequacy is a long-term concept that refers to having planned supply- and demand-side resources that exceed forecasted peak loads plus a planning reserve margin to account for forced outages of some generation units. Adequacy thus refers to the relationship between planned resources on the one hand and expected electricity loads and planning reserve requirements on the other hand.

Security and adequacy depend upon operating reserves and planning reserves, respectively. *Operating reserves* are, in any hour or dispatch interval, the amount by which available resources exceed load, where availability is determined not only by resources' nameplate capacities but also by the speed and extent to which they can respond to contingencies. *Planning reserves* are, in any year, the amount by which resources' total nameplate capacity exceeds annual peak loads. Operating reserves and planning reserves are thus indicators of system reliability in short- and long-term timeframes, respectively.

The purpose of this report is to examine issues of resource adequacy in both restructured and traditionally regulated markets in the United States. To achieve this purpose, we begin, in Section 3, by providing basic background on electricity market structures and capacity cost recovery mechanisms. Section 4 is devoted to reviewing and assessing the methods by which various industry organizations, government organizations, and regions determine capacity needs. Section 5 presents regional statistics on resource adequacy, resource mix, resource profitability, and capacity prices, and discusses the factors that influence these outcomes. Section 6 describes how technological advances may influence future reliability outcomes. Section 7 discusses various proposals for future reform of the means of assuring adequate capacity. Section 8 provides conclusions.

3. MARKET STRUCTURES

Traditionally regulated U.S. electricity markets have a hundred-year history of providing adequate generation capacity under nearly all circumstances. Nonetheless, questions have often been raised about the costs of providing and operating this capacity, particularly about whether the quantity of capacity has been too costly relative to the value of the reliability provided, whether generation investments have been efficient, and whether generation has been operated at least-cost. With such questions in the background, the energy crisis of the 1970s, the nuclear power cost overruns of the 1970s and 1980s, and the contemporaneous movement to deregulate other key infrastructure industries led to a search for new institutional arrangements that would shift generation investment risks from consumers to investors. The basic hope was that such a shift in risk would induce innovation in generation technologies, which did, in fact, occur; but these institutional arrangements also led to new issues and problems, many of which have yet to be resolved.

This section begins with an overview of electricity market structures and then describes the two general types of capacity cost recovery mechanisms.

3.1. Overview of Electricity Market Structures

About a third of the U.S. population continues to obtain electric power service through wholesale markets that are based on traditional institutional arrangements, while about two-thirds of the U.S. population obtains electricity through wholesale markets that have been substantially restructured to allow greater competition at the wholesale and/or retail levels. Both types of market – traditional and restructured – require mechanisms for assuring resource adequacy.

This section describes and compares each of these types of markets, and provides an overview of the states in which each market type prevails.

3.1.1. Traditional Markets[10]

In general, utilities with monopoly franchise service territories prevail in those areas of the U.S. that are not served by Regional Transmission Organizations (RTOs), though many such utilities do operate in RTO areas. These utilities are usually required to serve all retail customers within their respective service territories, in exchange for which they are granted an opportunity to earn a return on their investments commensurate with risk. This has commonly been referred to as the "regulatory compact," which involves an obligation to serve in exchange for exclusive service rights.[11] Because of this obligation to serve, utilities must procure sufficient short- and long-term resources to reliably meet customer needs within their service territories. They build and own their own generating units or do so jointly with other utilities, develop long-term purchase arrangements with independent power producers, or procure short- and long-term resources under negotiated bilateral power purchase agreements with entities that have surplus resources. Utilities recover the costs of procuring these resources by charging rates that are determined by their costs of service.

A bilateral capacity contract is an agreement between a willing buyer and a willing seller to exchange electricity, rights to generating capacity, or a related product under mutually agreeable terms for a specified period of time. Many non-RTO areas thus have non-centralized bilateral capacity markets in which various capacity suppliers compete to meet resource needs, often by building generation. Even in those areas in which there is little or no retail electricity competition, there may be significant wholesale competition to meet the needs of the monopoly utility. This wholesale competition has been promoted by various regulatory changes (like Federal Energy Regulatory Commission Order No. 888[12]) that have created non-discriminatory open transmission access.

Resource development continues to be supported by various sharing arrangements among utilities. Some utilities jointly develop and own power plants. Some utilities participate in reserve-sharing arrangements that allow participants to rely upon each other's capacity, which can reduce overall reserve requirements because of the diversity of different utilities' loads and resources.[13]

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[10] Traditional markets have evolved substantially over the past thirty years, particularly due to changes in law and regulation that have required most utilities, in both traditional and restructured regions, to offer non-discriminatory open access transmission service and to purchase capacity from third parties under certain conditions. The discussion of traditional markets should not be misinterpreted to suggest that these markets have been fixed in their design or operation, but that they have instead seen less radical change than has characterized restructured markets.

[11] There are some cases where limited retail competition is allowed even in states with exclusive franchises. For example, Georgia allows competition for new customers over a certain size.

[12] Federal Energy Regulatory Commission, Order No. 888, *Promoting Wholesale Competition Through Open Non-discriminatory Services by Public Utilities*, 75 FERC ¶ 61,080, Docket No. RM95-8-000, April 24, 1996.

[13] "Diversity" refers to the fact that different utilities serve customers with different load patterns, and different resources are available at different times. For example, California often sends power to the Pacific Northwest in

Most states in non-RTO areas have integrated resource planning (IRP) processes that determine resource requirements and that identify the resources that can meet those requirements at the lowest cost to customers. IRP processes consider present and future loads, existing and prospective supply- and demand-side resources, existing and prospective transmission capabilities, risk factors (like fuel diversity), and public policy requirements (like environmental restrictions and renewable resource laws). Based upon all these factors, IRP processes result in utilities building or purchasing capacity sufficient to meet the identified resource needs. Some states require utilities to allow third parties (such as independent generators) to compete, on a non-discriminatory basis, to meet these resource needs. Just as in restructured markets, utilities in traditional markets utilize the principles of cost-based economic dispatch of their capacity resources to minimize overall variable energy costs for customers based on the short-term incremental costs of each resource.

3.1.2. Restructured Markets

The restructured wholesale electricity markets are all located in regions covered by RTOs. The new institutional arrangements of these markets have fostered competition in generation services through new rules for transmission access and pricing and through the creation of RTOs (also called "Independent System Operators") that direct resource commitment and dispatch over wide geographic areas.

Many states in restructured market regions allow retail access. Retail access allows many consumers to shop for their power supply among competing firms, some of which are brokers or marketers that do not own generation. This competition provides incentives for innovation and cost-cutting in the provision of retail electricity services, and it also encourages suppliers to link retail prices to wholesale prices. Although the investments, expenditures, and rates of competitive retail electricity suppliers are not subject to state regulation, these suppliers are subject to light regulatory oversight under consumer protection rules. As a backstop, incumbent electric utilities usually retain an obligation to serve those customers who do not choose alternative suppliers.

In the absence of retail access, utilities procure capacity resources in much the same fashion as in traditionally regulated regions, except that capacity trades through the RTOs' centralized capacity markets are available on a mandatory or voluntary basis depending upon each RTO's rules. In states with retail access, regulators have often discouraged – or even prohibited – retail load-serving entities (LSEs) from owning their own generating resources, sometimes even barring LSEs from engaging in long-term contracts to hedge against short-term price fluctuations, under the assumption that such contracts would "lock in" high prices and prevent the benefits of competition from accruing to consumers.[14] These markets are dominated by

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the winter, when the Pacific Northwest has its highest electricity demand; and the Pacific Northwest often sends power to California in the summer, when California has its highest electricity demand.

[14] For example, under California's restructuring process retail providers were required or strongly encouraged to purchase all electricity in the spot market, under the assumption that any long-term contracts would become

organized spot market transactions in which all generators that clear the market get paid the market price, regardless of actual costs of their generation. These spot market transactions are centrally administered by the RTO, through which electricity can be purchased hourly on a real-time or day-ahead basis. Retail customers may not see this hourly or day-ahead price, however, as their particular contracts or regulatory situation determine the retail rates they pay.

The original theory was that, in these restructured wholesale markets, generation investment would be supported by competitively determined market prices for electrical energy and ancillary services which, through locational differentiation, would also induce generators to locate where generation services were most valuable. The reality, however, has been that:

- neither producers, consumers, regulators, nor legislators are able or willing to tolerate the extreme and unpredictable price volatility of unfettered electricity markets;
- in times of capacity shortage, the political process will not support interruption of service to consumers and retail suppliers who fail to arrange for adequate supplies, but instead tends to "share the pain" of shortages among all consumers, including those who *do* arrange for adequate supplies;
- the RTOs' short-term markets for electrical energy and ancillary services have not been accompanied by sufficient development of long-term markets for these services; and
- the market rules of the RTOs and of regulators occasionally change, usually with significant notice but sometimes unexpectedly.

The consequences of these realities have been supplier bankruptcies, disincentives for arranging long-term supplies, the inability of market participants to arrange long-term price hedges, and uncertainty about the durability of market rules.

Thus, contrary to the hopes of the 1980s and 1990s, public policy does not allow unfettered electricity markets to support investment in generation and other resources. Instead, the restructured markets have had price caps imposed to limit price volatility, with the result being that, under shortage conditions, the price mechanism does not encourage the provision of sufficient additional resources nor induce sufficient load reductions. Whether simply allowing prices to reflect shortage conditions by eliminating price caps would solve capacity adequacy issues is a moot question since regulators are not likely to allow the price volatility that could result.

To avoid the shortages that the price mechanism is not allowed to handle, an assortment of administrative rules have been put in place specifying the quantities and locations of the resources that must be procured. In short, RTO regions' capacity needs are determined by administrative rules, RTO capacity markets identify the amounts (but not types) of resources

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uneconomic as competitive pressures caused wholesale prices to fall. This turned out to be an extremely costly mistake when wholesale prices skyrocketed in the winter of 2000-01 and 100% of the non-municipal load in the state was unhedged.

that meet these needs, and it is hoped that the resulting capacity prices will support investment. This approach has not been enough to fully solve the resource adequacy problem, however, because the RTOs' capacity markets cover at most only the first few years of the life of decades-long generation investments, and because there are uncertain relationships between capacity on the one hand and the energy and ancillary services that they provide on the other. RTOs' determinations of capacity needs must therefore evolve over time to reflect how renewable resource intermittency, changing forced outage rates of power system components, uncertain future technological change, uncertain future economic conditions, uncertain electricity market rules, and uncertain future government regulatory policies affect the uncertain ability of capacity to provide the energy and ancillary services that consumers need.[15]

3.1.3. Overview of Prevalent Market Types in Each State

In addition to the distinction between traditional and restructured electricity markets, there is also a distinction among the states in their authorization of retail access. This latter distinction is important because it has influenced how the states deal with resource adequacy. For example, states without full retail access (such as Georgia[16] and North Carolina) rely on integrated resource planning. Unlike full retail access states, they have not ordered their utilities to acquire capacity through a reverse auction of load responsibility (as occurs in New Jersey) or with regular utility semi-annual wholesale power procurements (as occurs in Maryland).

The RTO regions also encompass retail markets that have not restructured. In these situations, wholesale market prices are largely determined by the centralized RTO markets, while retail prices are determined on a traditional cost-of-service basis, where costs are influenced by prices in the RTOs' wholesale markets.

Considering these two dimensions – traditional versus restructured markets, retail access versus no retail access – we divide the 48 contiguous states and the District of Columbia into the three groups:

- *Restructured Retail Access States* that are within RTOs and that permit retail competition among suppliers;

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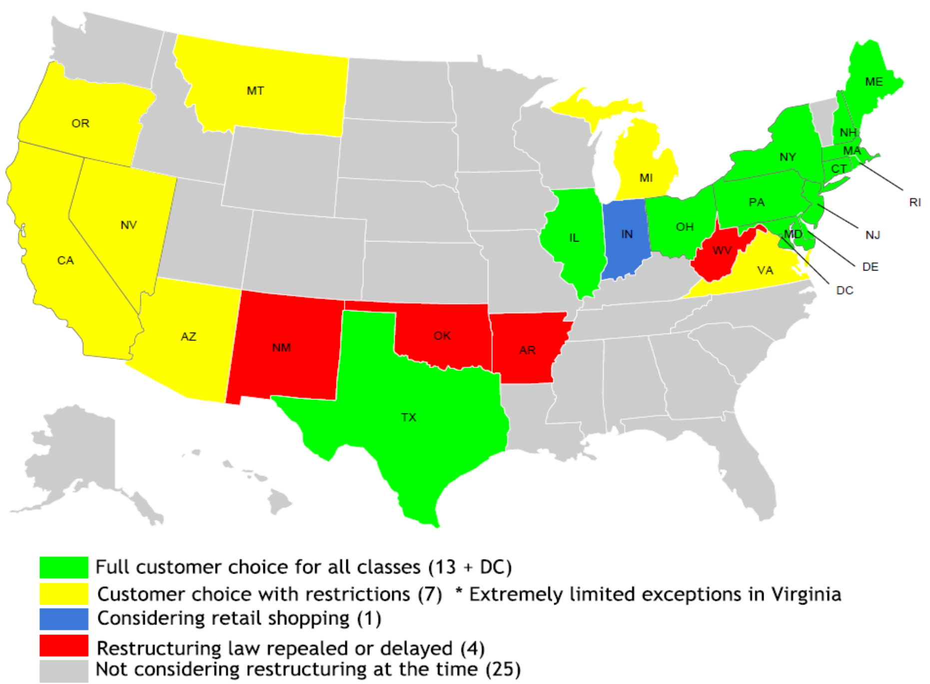
[15] The current Federal Energy Regulatory Commission proceeding on revisions to the capacity market of the Midcontinent Independent System Operator (Docket No. ER11-4081-001) is the latest in a series of FERC proceedings to revise key characteristics of the capacity markets under its jurisdiction. Texas, meanwhile, is in the midst of a long and contentious process by which it seems to be heading toward adopting its own RTO-administered capacity market.

[16] Some retail competition has been present in Georgia since 1973 with the passage of the Georgia Territorial Electric Service Act. This Act enables customers with manufacturing or commercial loads of 900 kW or greater a one-time choice in their electric supplier. It also provides eligible customers the opportunity to transfer from one electric supplier to another if all parties agree. See http://www.psc.state.ga.us/electric/electric.asp.

- *Restructured Non-Retail Access States* that are within RTOs and that do not permit retail competition; and
- *Traditionally Regulated States* that are not within RTOs and that do not permit full retail competition.

As shown in Figure 1, all states with retail access are all located in regions covered by RTOs, so no state falls in the theoretically possible category of being a non-RTO state with full retail access. Instead, 13 states and the District of Columbia, mainly concentrated in the Northeast, are covered by RTOs and offer retail access; 11 states, mainly concentrated in the Midwest, are covered by RTOs and permit little or no retail competition; and 24 states, mainly concentrated in the Southeast and West, do not have RTOs and permit little or no retail competition.

Figure 1
Division of States by Retail Access Status[17]



3.1.4. Similarities and Differences Among the Market Types

Table 1 shows how the three market types – restructured retail access, restructured non-retail access, and traditionally regulated – are similar to and different from one another. In all

[17] Compete Coalition, http://www.competecoalition.com/about.

markets other than Texas,[18] LSEs have an obligation to procure capacity – either owned or procured under contract – that is sufficient to serve their own retail load. The RTOs offer an additional venue – their centralized capacity markets – in which LSEs can procure capacity. Consumers have a choice of retail supplier only in markets with retail access, in exchange for which utilities have a more limited obligation to serve than in markets without retail access.[19] While retail rates continue to be cost-based in markets without retail access, they are more market-based in markets with retail access in that the energy portion of rates depends on a pass-through of the wholesale cost of the electricity procured in the wholesale market.

Table 1
Similarities and Differences Among Market Types

Characteristic	**Market Type**		
	Restructured Retail Access	**Restructured Non-Retail Access**	**Traditionally Regulated**
Capacity planning forum	RTO / IRPs or LTRPs[20]	RTO / IRPs	IRPs
LSE obligation to procure capacity sufficient to serve own load	no	yes	yes
Acceptability in meeting capacity obligation:			
Owned capacity	yes	yes	yes
Bilaterally contracted capacity	yes	yes	yes
Centralized market purchases	yes	yes	not applicable
Consumer choice of supplier	mostly yes	No, or severely restricted	No, or severely restricted
Utility obligation to serve	limited	yes	yes

[18] In Texas, retail energy providers (REPs) serve retail electric consumers without bearing a requirement to secure capacity sufficient to meet their load.

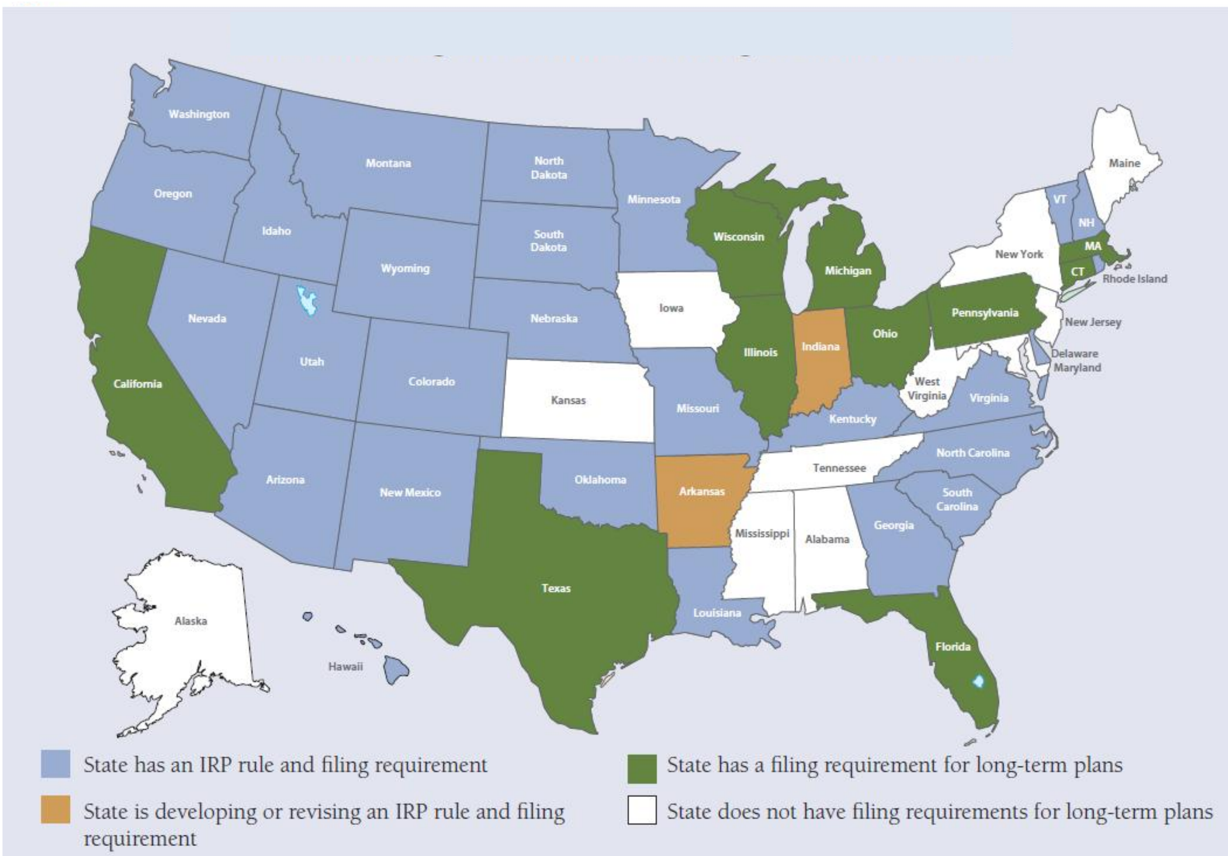
[19] In retail access states, distribution utilities have an obligation to serve customers regardless of which supplier the customer chooses. The investments, expenditures, and rates of distribution utilities are still regulated by state regulatory agencies. In addition, distribution utilities are required in most retail access states to offer "default service" to customers who, for whatever reason, do not actually choose a supplier or cannot obtain service from a competitive supplier. The prices and terms of this default service are also regulated by the state regulatory agency.

[20] Requirements for long-term resource plans (LTRPs) differ from requirements for IRPs. For LTRPs, planning periods are typically ten years, although some states require a five-year planning period with yearly updates. Because utilities in states with LTRPs operate in restructured retail markets and typically do not own generation, LTRPs evaluate purchases for capacity and energy, as well as energy efficiency and other demand-side management programs.

Basis of retail rates	market prices for energy and reserves, cost for wires	cost	cost

Figure 2 shows that a vast majority of the states have an IRP requirement, including a significant number of states that are part of an RTO. Furthermore, many other states in RTO regions require LSEs to file long-term resource plans that supersede the IRPs that existed prior to the restructuring of the retail market.

Figure 2
States with Integrated Resource Planning or Similar Processes[21]



3.2. Capacity Cost Recovery Mechanisms

In principle, there are two basic methods by which the required amount of capacity can be determined. First, the required amount of capacity can be determined through purely market

[21] Synapse Energy Economics Inc., *Best Practices in Electric Utility Integrated Resource*, June 2013, Figure 2, p. 5.

processes, whereby investors build capacity when they expect that the market prices of electricity services will be sufficiently high to make their investments profitable.[22] Second, some agency – like a reliability organization, state regulators, RTOs, or utilities themselves – can determine the capacity requirement.

The methods by which capacity costs are recovered are determined, in large part, by the methods for determining the capacity requirement. When the capacity requirement is determined by the market, capacity costs must be recovered through market prices. When the capacity requirement is determined by an agency or by a utility satisfying a regulatory requirement, there needs to be some scheme for more or less guaranteeing recovery of prudently incurred costs.

3.2.1. Cost Recovery Under a Purely Market Scheme

Under a purely market scheme, there would be no "capacity" product. Instead, investors would develop resources when they expect to profit from the sales of energy and ancillary services at projected market prices. Such sales may be at spot (real-time) prices, but resource owners and customers would generally seek to avoid price volatility through derivative contracts such as long-term bilateral sales contracts and option contracts. Capital costs and operating costs would be recovered solely through revenues from the sale of these services. When demand threatens to exceed available capacity, high energy and ancillary services prices would encourage immediate load reductions, often through demand response programs (though in some instances through utility-imposed load curtailments); and investment would respond to expectations of persistent high prices.

That is the theory.

In real electricity markets, by contrast, energy and ancillary services prices are significantly distorted, and cost recovery is seriously undermined, by the following circumstances and policies:

- In some RTO regions, limited demand-side participation and electricity customers' general insulation from volatile wholesale electricity prices restrict the extent to which market prices and capacity choices are influenced by consumers' values of electricity services.
- RTOs' out-of-market purchases of energy and ancillary services, by increasing short-term energy and reserve supply for the purpose of improving short-term reliability, have the side-effect of depressing energy and reserve prices.[23]

[22] As discussed below, this first approach is not likely to result in capacity sufficient to meet traditional capacity requirements or the laws or regulations related to such requirements.

[23] The RTOs' system operators often find that the market cannot be relied upon to provide sufficient energy and ancillary services in the right locations. Consequently, for the purpose of assuring power system reliability, they make "out-of-market" side deals by which they pay particular generators to provide energy, voltage support, or operating reserves that these generators would not be willing to provide at market prices. The RTOs recover these

- Energy and ancillary service prices are generally subject to caps, partly to reduce the price volatility borne by consumers and partly because of concerns that high prices may be due to exercises of supplier market power. These price caps limit cost recovery under shortage conditions, thereby depriving capacity resources of what could otherwise be a significant source of revenues. This leads to the so-called "missing money" problem, which inhibits new investment in restructured markets.
- The investment problem is particularly acute because of the nature of electricity demand. Customer demand has a profile that includes baseline needs during normal weather conditions and usage, and higher peak demands during particularly cold or hot weather (depending on the region). A mix of generating technologies satisfies this range in electricity demand at least cost. The generators that serve demand only during peak load hours may be needed to run only a few days or even a few hours each year. Although such peaker plants have relatively low capital costs, they nonetheless need extremely high prices during those few days or hours to earn revenues sufficient to cover both the variable and fixed costs, including a return on their investment in capacity. Inconsistent with this need, however, the restructured markets have caps on generators' offer prices, thus precluding market prices from reaching levels high enough to provide the needed revenue for the peaker plants during those few hours when they are needed. This "missing money" problem extends beyond peaker plants to all other plant types, including baseload plants. The restructured markets' capacity market mechanisms are intended to make up for the "missing money" and provide sufficient incentives for investment in both base load and peaking generation – so far with limited success.
- Policies that support particular types of capacity resources – such as renewable resource portfolio standards or tax credits for renewable resource investments – have the implicit effect of subsidizing the preferred resources while "taxing" other resources. The "tax" on other resources occurs in the form of reduced market prices for energy, ancillary services, and capacity due to the presence and operation of the preferred, subsidized resources.[24,25]

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extra payments through uplift charges of various sorts, generally imposed on all load. The generators who receive these payments supply of energy and ancillary services that they would not provide without these payments; and this extra supply has the effect of reducing energy and ancillary services prices relative to what they would otherwise be.

[24] This is the gist of the Electric Power Supply Association's complaint that capacity and energy markets are undermined by price discrimination in favor of certain preferred resources. See *Statement of Michael M. Schnitzer, Co-founder and Director of The NorthBridge Group, on behalf of the Electric Power Supply Association*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, before the Federal Energy Regulatory Commission, Docket No. AD13-7-000, September 9, 2013.

[25] The size of this tax on other resources has been estimated for the Texas power market for the years 2013 through 2015. For this period, Texas' state renewable resource policies will depress peaker margins by about $6 per kW-year and natural gas combined-cycle margins by about $14 per kW-year. See M. Kline, B. Gibbs, and R.

- U.S. power industry practice sets planning reserve requirements at levels that exceed many customers' willingness to pay for reliability.[26] In general, it might be cheaper for many customers to suffer more bulk power system-related outages than to pay for the resources needed to avoid those outages, even considering (for example) business customers' costs of lost production, lost sales, and additional production equipment repair and maintenance costs following an unexpected outage. Outage costs do vary widely among customers. Nonetheless, because many customers' willingness to pay for reliability is generally well below that needed to support the power industry's usual planning reserve requirements as determined by public policy, markets alone will not support the capacity requirements implied by the power industry's reliability practices, even with a perfectly functioning demand-side of electricity markets.

The latter four policies all restrict or reduce market prices; and the latter two policies require capacity that would not be supported by free markets. Eliminating these policies is simply not realistic. Consequently, given the likelihood that these policies and market design practices will remain in place, capacity costs will not be recoverable under a purely market scheme and investment in new capacity will continue to be suppressed.

3.2.2. Cost Recovery With a Capacity Requirement Scheme

Capacity requirement schemes characterize both traditional and RTO markets. Such schemes impose capacity obligations on individual LSEs for specified present and future periods (such as three years ahead). These obligations can be enforced through penalties, or LSEs may meet their requirements merely as a matter of good business practice.

Capacity requirements are generally set at some level in excess of the LSE's customers' peak loads plus any wholesale sales obligations that the LSE may have under contract. This excess is

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Muthiyan, "When Free Markets Aren't Free: Failure of the ERCOT Energy-Only Market," Berkeley Research Group, August 2013, p. 1.

[26] For example, one report finds that ERCOT's reliability target of "one load-shed event in 10 years" implies a need for a 15.25% reserve margin; but customer willingness-to-pay $9,000 per MWh to avoid curtailment implies a need for only a 10% reserve margin. See S. Newell, K. Spees, J. Pfeifenberger, R. Mudge, M. DeLucia, and R. Carlton, *ERCOT Investment Incentives and Resource Adequacy*, Brattle Group, prepared for Electric Reliability Council of Texas, June 1, 2012, p. 3. The $9,000 value is roughly the magnitude of multiple studies of the costs that customers incur due to curtailment.

Another report finds that the reliability target of "one load-shed event in 10 years" implies customer willingness-to-pay of $300,000 per MWh to avoid curtailment, an absurd result that is equivalent to an average homeowner paying $900 for one hour's worth of power. The $300,000 figure assumes that: a) the carrying cost of new capacity is $90,000 per MW-year; and b) that a typical resource-related firm load shed event lasts three hours. $300,000 = $90,000 per MW-year / [(3 hours per event) / (1 event per 10 years)]. Note that the $90,000 figure is consistent with the $891 per kW cost of a combustion turbine peaking unit shown in Figure 16: $90,000 = $891 per kW * 1000 kW per MW * 10.1% cost of capital. See Astrape Consulting, *The Economic Ramifications of Resource Adequacy*, for Eastern Interconnection States' Planning Council and National Association of Regulatory Utility Commissioners, January 2013, p. 1.

the planning reserve margin, usually a number in the range of 12% to 18% of peak load. The determination of capacity requirements thus depends upon load forecasts, which are more uncertain for individual LSEs in competitive retail situations wherein customers may shift among LSEs than in monopoly situations in which a single LSE can count on serving the whole market.

LSEs can fulfill their capacity obligations through resource ownership or resource rights conferred by contract. Contractual resource rights may be procured in bilateral markets and, in some RTOs, in centralized capacity markets.[27]

There is some complexity, however, in defining precisely what qualifies as "capacity" that meets the obligations. In principle, elements of this definition could include the following:

- supply-side versus demand-side resources versus transmission resources;
- resource technology (such as fuel type);
- performance requirements (such as minimum availability rates, speed of availability, dispatchability by the system operator);
- requirements for substantiating expected performance;
- requirements for power deliverability;
- requirements for firm fuel transportation;
- timeframe of the capacity obligation (such as one month ahead or five years ahead); and
- quantification of capacity (such as crediting dispatchable resources with their full nameplate capacities while crediting intermittent resources with only a quarter of their nameplate capacities).

Capacity investors must have a reasonable expectation that they will recover the capital costs of their investments regardless of the institutional arrangements under which the investment is made. The capital cost recovery methods are very different under traditional regulatory schemes than under restructured market schemes.

Traditional Recovery Through Cost-of-Service Based Rates

Traditionally, capacity costs have been recovered from retail customers through retail charges based upon those costs. In general, cost-of-service ratemaking annualizes capacity costs according to some measures of capital costs (like interest rates), assigns these costs to the utility's functions (particularly generation), allocates the functionalized costs among customer classes or groups, and then divides class-level costs by some class-level billing determinants (like peak loads or energy sales) to derive retail prices. The costs that are recovered through

[27] LSE participation in centralized capacity markets may be mandatory or voluntary, depending upon the RTO.

these retail prices may be lower or higher than costs actually incurred depending upon the accuracy of the forecasts (particularly the load forecasts) that went into the price calculation.

There are two main factors that make traditional recovery of capacity costs uncertain. The less important factor is the inevitable misforecasting of the loads and costs that underlie the calculation of retail prices. These misforecasts might reasonably be expected to offset each other over the life of a capacity resource, which makes the uncertainty relatively minor over the resource's life. The more important factor, for regulated utilities, is uncertainly of the extent to which regulators will accept the prudency of capacity investments, which depends, in large part, on the extent of any capacity cost overruns. In short, under traditional regulation, the prudency of a capacity resource investment largely determines the uncertainty in the recovery of capacity costs. A utility can pretty much count on recovering those capacity investment costs deemed prudent by regulators.

Competitive Recovery With Capped Energy and Ancillary Services Prices

Recovery of capacity costs in a competitive market context requires either: a) regulatory or administrative support of market prices, such as Minimum Offer Price Rules that discourage investment in some capacity resources as a counterbalance to those policies that encourage investment in other (possibly subsidized) capacity resources; and/or b) imposition of implicit "taxes" on electricity consumers, which is accomplished primarily through the capacity requirements imposed on LSEs. It also requires the imposition upon LSEs of stiff penalties for failure to procure sufficient capacity – through owned or purchased capacity – to meet their respective requirements.

Because of the policies (enumerated in Section 3.2.1) that distort and depress the market prices of electricity services, capacity cost recovery in competitive markets depends upon the mandatory resource requirements imposed upon LSEs. Because the mandatory requirements raise the costs of *all* LSEs, each individual LSE is able to raise its retail prices to recover these costs without fear of losing customers to competitors. Nonetheless, these mandatory requirements have, in practice, often been insufficient to assure full capacity cost recovery and thereby provide insufficient incentives for investors to develop new resources.

4. DETERMINATION OF CAPACITY REQUIREMENTS

Capacity requirements are determined first and foremost by the need to maintain power system reliability. Reliability needs are generally translated into capacity requirements through various rules of thumb that are implemented through engineering analysis of probable reliability outcomes, with the objective of minimizing costs subject to meeting the reliability requirement.

This section describes the regulatory context in which capacity requirements are determined, and then looks at the actual and proposed practices of certain entities responsible for assessing resource adequacy.

4.1. Regulatory Context

Various reliability and regulatory agencies impose overlapping rules on the utilities, transmission owners, and system operators who are responsible for the day-to-day and minute-to-minute tasks of maintaining power system reliability. In general, the national standards set minimum criteria, while more local standards can set higher criteria.

For example, resource adequacy in New York State depends upon the various rules established by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), the New York State Reliability Council (NYSRC), the Federal Energy Regulatory Commission (FERC), the New York Public Service Commission, and the New York Independent System Operator (New York ISO).[28] Because of the particular reliability needs of the northeast region, NPCC regional level standards may be more stringent than the national-level standards of NERC. Because of New York's particular reliability needs, NYSRC's state-level standards may be more stringent than the regional-level standards of NPCC.

Following the national-to-local scheme, this section begins at the highest level – the North American Electric Reliability Corporation – and then sequentially looks at Regional Reliability Entities, FERC, and state requirements.

4.1.1. North American Electric Reliability Corporation Standards[29]

NERC develops reliability standards in collaboration with stakeholders in the U.S. and Canadian bulk power systems. The standards are based upon power engineering models that estimate how actual and proposed standards are likely to affect the bulk power system's performance and risks.[30] NERC does not set reserve margins or mandate resource development (such as the building of generation or transmission facilities). Instead, NERC develops reliability standards, independently assesses reliability issues, and identifies emerging reliability risks.

NERC's Reliability Standards define the power system operating and planning requirements to which each entity responsible for operating or planning the bulk power system must adhere. Each standard must be consistent with all of the following Reliability Principles:[31]

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[28] New York State Reliability Council, *Reliability Rules For Planning And Operating the New York State Power System*, Version 31, May 11, 2012, p. 4.

[29] Sources of this section include http://www.nerc.com/pa/stand/Pages/default.aspx; North American Electric Reliability Corporation, *Reliability Standards for the Bulk Electric Systems of North America*, December 12, 2013, http://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf; and North American Electric Reliability Corporation, *Reliability and Market Interface Principles*, undated, http://www.nerc.com/pa/Stand/Standards/ReliabilityandMarketInterfacePrinciples.pdf.

[30] http://www.nerc.com/pa/stand/Pages/default.aspx.

[31] North American Electric Reliability Corporation, "Reliability and Market Interface Principles," undated, http://www.nerc.com/pa/Stand/Standards/ReliabilityandMarketInterfacePrinciples.pdf.

Reliability Principle 1	Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
Reliability Principle 2	The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
Reliability Principle 3	Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
Reliability Principle 4	Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
Reliability Principle 5	Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk electric systems.
Reliability Principle 6	Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
Reliability Principle 7	The security of the interconnected bulk electric systems shall be assessed, monitored, and maintained on a wide-area basis.

Each standard must also be consistent with all of several Market Interface Principles that are intended to facilitate electricity competition without discriminating in favor of or against any particular market participant.

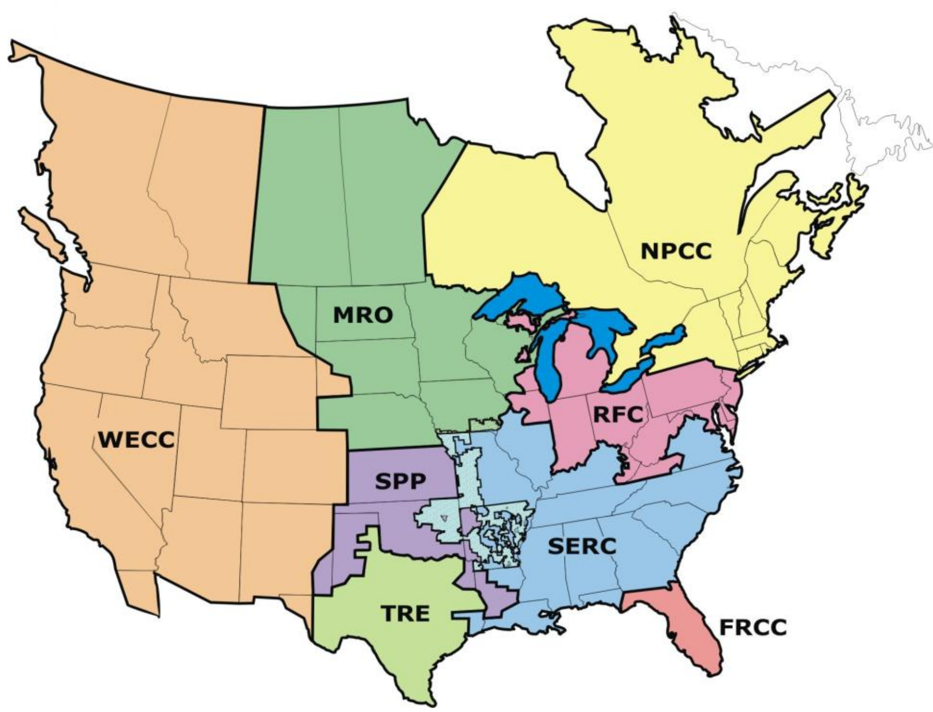
4.1.2. Regional Reliability Entities Standards

NERC delegates authority to regional reliability entities that are responsible for promoting and improving the reliability, adequacy, and critical infrastructure of their respective regional power systems. These entities serve each of the several NERC reliability regions shown in Figure 3. Each regional entity develops, updates, monitors, and enforces reliability standards within its own region, without discrimination among market participants. These standards may be tailored to regional circumstances, but must be consistent with NERC standards. The regional reliability entities may also help coordinate power system planning, design, and operations.

For each of the eight regional reliability entities, resource requirements – or, equivalently, planning reserve requirements – are determined as follows:

- Florida Reliability Coordinating Council (FRCC), in collaboration with the Florida Public Service Commission, requires that investor-owned utilities (IOUs) maintain a 20% planning reserve margin while non-IOUs maintain a 15% reserve margin.[32]
- Midwest Reliability Organization (MRO) has two subregions – Mid America Power Pool (MAPP) and the Midcontinent Independent Transmission System Operator (MISO). MAPP uses NERC's 15% reserve margin target for utilities within that sub-region of the MRO. Resource requirements in MISO are determined as described in Section 4.2.1.
- Northeast Power Coordinating Council (NPCC), in its U.S. portion, is divided between ISO New England and the New York ISO. The reliability criteria and targets for planning reserve requirements for these RTOs are determined as described in Section 4.2.1.

Figure 3
NERC Reliability Regions[33]



[32] North American Electric Reliability Corporation, *2013 Summer Reliability Assessment*, May 2013, p. 8.

[33] The reliability regions are Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RFC), SERC Reliability Corporation (SERC), Southwest Power Pool Regional Entity (SPP), Texas Reliability Entity (TRE), and Western Electricity Coordinating Council (WECC).

- ReliabilityFirst Corporation (RFC) is split between Midcontinent ISO and PJM. Therefore, the reliability criteria and targets for these RTOs' planning reserve requirements are established as described in Section 4.2.1.
- SERC Reliability Corporation (SERC) is guided by the NERC benchmark of 15% planning reserves as well as by reliability criteria that apply to each of the sub-regions and power systems within SERC. SERC uses region-wide reliability criteria only to the extent that the criteria applied to smaller areas do not adequately address reliability for the whole region. Subject to the foregoing and to the condition that each financial entity within SERC is responsible for serving its own load, each financial entity determines its own planning reserve requirement. Nonetheless, capacity planning is coordinated among the entities within each sub-region.
- Southwest Power Pool Regional Entity (SPP) has a Reference Margin Level of 13.6%.[34]
- Texas Reliability Entity (TRE) has a Reference Margin Level of 13.75%. This figure is based on a target of no more than 0.1 loss-of-load events per year.[35] Electric Reliability Council of Texas (ERCOT) stakeholders are currently reviewing a recently completed loss-of-load study that supports the target reserve margin determination. A final decision by the ERCOT Board is expected later this summer.
- Western Electricity Coordinating Council (WECC) covers a very large geographic region that is divided into 19 reliability assessment zones. Target reserve margins in the U.S. zones for summer range between 12.6% and 17.9%, averaging 14.8%, while those for winter range between 11.0% and 19.9%, averaging 14.3%. For the Canadian zone, the figures are 12.4% and 14.0%, while for the Mexico zone, the figures are 11.9% and 10.7%. Thus, the U.S. zones tend to have higher target reserve margins than those of Canada and Mexico. For WECC as a whole, that target reserve margin is 14.6% in both summer and winter.[36]

In addition to regional entities, there are sub-regional entities (like the NYSRC) that may impose reliability standards that go beyond those of the regional entities.

4.1.3. Federal Energy Regulatory Commission Requirements

FERC has issued several important orders pertaining to the organization of RTO capacity markets. Some of these orders have been generic orders that address market design issues, among which capacity markets and/or resource adequacy issues are a part.[37] Other orders

[34] North American Electric Reliability Corporation, *2013 Summer Reliability Assessment*, May 2013, p. 142.

[35] North American Electric Reliability Corporation, *2013 Summer Reliability Assessment*, May 2013, p. 19.

[36] Western Electricity Coordinating Council, *2012 Power Supply Assessment*, October 15, 2012, Table 7, p. 7.

[37] These include, for example, Order No. 719 (Federal Energy Regulatory Commission, *Wholesale Competition in Regions with Organized Electric Markets*, 125 FERC ¶ 61,071, Docket Nos. RM07-19-000 and AD07-7-000, October

have addressed the details of how individual RTO's capacity markets are designed.[38] The general thrust of these orders has been to promote the following:

- Non-discriminatory treatment of generation, demand response, and transmission as capacity resources;
- Recognition of the importance of capacity locations, to account for transmission constraints that limit deliverability;
- Encouragement of advance commitment of capacity, to support planning and allow time for capacity construction or development;
- Determination of capacity prices according to peaking plant revenue requirements net of energy and ancillary service market revenues.

Within the general thrust of its policy, FERC has allowed the RTOs significant latitude in setting the details of how their capacity markets work, including differences in how the RTOs determine capacity requirements, define capacity, set capacity performance requirements, mandate capacity market participation, set the timing of capacity commitments, conduct auctions, determine capacity prices, and mitigate market power.

4.1.4. State Requirements

State reliability requirements are consistent with those established by NERC, the Regional Reliability Entities, and FERC. They do, however, sometimes go beyond the national and regional requirements.

4.2. Requirements of the Regional Transmission Operators

This section describes, compares, and assesses the methods by which each of the RTOs' determines its capacity requirements.

4.2.1. Methods for Determining Capacity Requirements

Capacity requirements are usually determined by the amount of capacity that will achieve some reliability target (like one outage event in ten years) under peak load conditions. The critical determinants of capacity requirements are therefore the reliability targets, forecast peak loads, and the modeling assumptions that relate power system conditions to reliability outcomes.

17, 2008) and Order No. 745 (Federal Energy Regulatory Commission, *Demand Response Compensation in Organized Wholesale Energy Markets*, 134 FERC ¶ 61,187, Docket No. RM10-17-000, March 15, 2011).

[38] These include, for example, Federal Energy Regulatory Commission, *Initial Order on Reliability Pricing Model*, *PJM Interconnection, L.L.C.,* 115 FERC ¶ 61,079, Docket Nos. EL05-148-000 and ER05-1410-000, April 20, 2006; and Federal Energy Regulatory Commission, *Order Accepting Market Rules*, *ISO New England, Inc.*, 119 FERC ¶ 61,239, Docket No. ER07-547-000, June 5, 2007.

Because of transmission limitations, capacity requirements are set by zones that are defined by existing transmission constraints. Significant changes in power system configurations, notably including additions or retirements of generation or transmission facilities, can change the definitions of zones.

Retail choice creates substantial uncertainty in the quantity of load that will be served by any LSE. For a monopoly utility, the load in any particular year is uncertain because of the major common factors – weather and economic conditions – that affect all loads and are uncertain on an annual time scale. For LSEs competing to serve customers, the load in any particular year depends not only on the major common factors but also on competitors' business strategies, consumer preferences, market campaign successes and failures, and other competitive conditions. Consequently, the load uncertainty faced by an LSE in a retail choice environment is proportionally much greater than the load uncertainty faced by an LSE in a market without retail choice.

Because each LSE's capacity obligation depends upon the quantity of load that it serves, the obligation in retail choice environments is proportionately much more uncertain than in non-retail choice environments. Furthermore, this relatively larger uncertainty increases with longer forward timeframes. For example, an LSE's capacity obligation is much more uncertain three years in advance than one month in advance.

California Independent System Operator

The California Independent System Operator (California ISO) tariff requires LSEs to have generation capacity equal to at least 115% of each month's forecast peak demand. The 15% planning reserve requirement covers operating reserves (about 7% of load) plus an allowance for resource outages and other potential resource deficiency issues (about 8% of load). LSEs may be required to procure additional resources to address reliability issues in certain local areas.

Electric Reliability Council of Texas

ERCOT does not have a capacity market, though it is considering the possibility of adopting one.[39] Although a 13.75% planning reserve margin is implied by its target reliability standard of one-in-ten-year loss-of-load expectation (LOLE), ERCOT does not have a formal resource adequacy requirement. Instead, LSEs procure resources as they think appropriate in accordance with their expectations of future electrical energy prices. Consequently, actual planning reserves in the ERCOT market are the aggregate result of LSEs' individual investment decisions.

[39] The Public Utility Commission of Texas together with the ERCOT has commissioned a significant amount of research into the question of how best to ensure resource adequacy in Texas. A contentious debate continues over whether the Texas electricity market needs a formal capacity market to solve its resource adequacy issues. A most recent addition to the research on the question is The Brattle Group, *Estimating the Economically Optimal Reserve Margin in ERCOT*, prepared for the Public Utility Commission of Texas, January 31, 2014.

ISO New England

ISO New England forecasts loads according to historical loads and forecasts of future real income and real electricity prices.[40] Based upon this load forecast, it determines the amount of additional capacity, on top of existing capacity, that would be needed to achieve a one-in-ten-year LOLE. With various adjustments for Hydro-Québec Interconnection Capability Credits and import capability, the Installed Capacity Requirement (ICR) is then set equal to: a) existing capacity; times b) one plus the ratio of the needed additional capacity to summer peak load.[41]

ISO New England has capacity requirements for each of four Capacity Zones: the Maine Load Zone, the Connecticut Load Zone, the Northeastern Massachusetts Load Zone, and the Rest of Pool Capacity Zone.[42]

Midcontinent Independent Transmission System Operator

Resource adequacy requirements in the MISO region are set by state regulators and influenced by stakeholders and FERC. Resource adequacy requirements therefore vary by state.

Nonetheless, MISO performs an annual LOLE study that serves as the basis for its minimum Planning Reserve Margin (PRM) for the upcoming planning year and its PRM forecast for the subsequent nine years. The LOLE study considers generators' performance, planned maintenance outages, and forced outages; load forecast uncertainty; and transmission congestion. MISO relies on its members for load and other information that determines the PRM. The PRM is not mandatory.

New York Independent System Operator

New York ISO's capacity requirement equals forecast peak load plus an Installed Reserve Margin (IRM) requirement.[43] New York ISO forecasts peak load by escalating historical peak loads according to forecast growth of loads and of dispatchable load management programs.[44] The NYSRC sets the IRM requirement to achieve a one-in-ten-year LOLE, where the calculation of the LOLE depends upon "demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring control areas, NYS

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[40] ISO New England, *Regional Long-Run Energy and Peak Load Forecast (2012-2021)*, System Planning, presentation to NEPOOL LFC Meeting, January 31, 2012.

[41] ISO New England, *ISO New England Installed Capacity Requirement, Local Sourcing Requirements, and Maximum Capacity Limit for the 2014/15 Capability Year*, April 2011, p. 11 and p. 25.

[42] ISO New England, *Market Rule 1*, Section III.12.4, p. 143.

[43] New York Independent System Operator, *Installed Capacity Manual*, August 2011, p. 2-3.

[44] New York Independent System Operator, *NYISO Load Forecasting Manual*, Manual 6, April 2010, pp. 1-1 – 1-2, http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp.

Transmission System emergency transfer capability, and capacity and/or load relief from available operating procedures."[45]

PJM

PJM's capacity requirement equals forecast peak load plus an IRM requirement. PJM considers weather conditions and economic growth in its forecasts of peak loads.[46] It sets the IRM requirement so as to achieve an "acceptable level of reliability" as determined by forecasts of loads, generator forced outage rates, and generator maintenance schedules.[47] PJM differentiates capacity requirements by Locational Deliverability Area, each of which is defined by actual past transmission constraints, potential future transmission constraints, or a perceived reliability need.

Southwest Power Pool

Southwest Power Pool (SPP) requires that most LSEs have capacity equal to at least 112% of their system peak responsibility, while LSEs with resources that are at least 75% hydroelectric are required to have capacity equal to at least 109% of their system peak responsibility.[48] Each LSE's "system peak responsibility" is defined as its peak annual load plus firm wholesale power sales at the time of its annual peak less firm wholesale power purchases at the time of its annual peak.

4.2.2. Determination of Capacity Prices

In a market context, the incentives for resource investment depend upon the costs that can be recovered through markets over the long term. Because these markets include capacity markets, the determination of capacity prices can affect resource investment incentives.

In the eastern RTOs (that is, New England, New York, and PJM), centralized market capacity auctions are held for specific future time periods (up to four years in advance) and at specific intervals. The auctions may have several rounds to allow market participants to adjust their positions and find market equilibrium. Resources that are accepted in each auction are those that have bid below the relevant market-clearing price: they are paid a market-clearing price that reflects the netting of the revenues (if any) that a pure peaking generator would earn from energy and ancillary services sales. Capacity prices are determined by the intersections of supply and demand curves for each season and each relevant capacity market zone. Supply

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[45] New York State Reliability Council, LLC, *New York Control Area Installed Capacity Requirements for the Period May 2012 - April 2013*, December 2, 2011, p. 3.

[46] PJM Interconnection, *Load Forecasting and Analysis*, Manual 18, November 16, 2011.

[47] PJM Interconnection, *PJM Capacity Market*, Manual 18, November 11, 2011, p. 7 and p. 9; and PJM Interconnection, *PJM Resource Adequacy Analysis*, Manual 20, June 1, 2011, pp. 21-34.

[48] Southwest Power Pool, *Southwest Power Pool Criteria*, Section 2.1.9, April 25, 2011.

curves are determined by the capacities and offer prices of the resources offered in each auction. Demand curves are administratively determined by each RTO, and depend principally upon the estimated cost of new entry of a pure peaking generator (net of energy and ancillary services revenues) and the capacity that is required to meet reliability criteria for each zone. The market-clearing price and the market-clearing quantity are determined by the intersection of the supply and demand curves. In the event of failure to perform, accepted resources may be penalized and may be liable to pay for replacement capacity.

ISO New England has a mandatory centralized capacity market through which LSEs trade capacity up to three years in advance and, for new capacity, can obtain guaranteed prices for up to five years. Its auction begins at a high price that yields more capacity than the ICR. The price is then reduced until the cleared capacity exactly meets the ICR and the requirements for each of local capacity zones. Existing capacity resources are price-takers that clear the auction automatically. New capacity resources, which are those that have not cleared in a previous auction, must bid to receive compensation. Only new capacity offers determine the clearing price, while existing capacity resources influence the clearing price only by exiting the auction. Capacity and capacity prices are differentiated by zone.

MISO has a voluntary centralized capacity market through which LSEs can trade capacity one year in advance. LSEs can opt out of the centralized market if they procure sufficient resources through resource ownership or bilateral contracts. LSEs without sufficient resources must pay a penalty charge that is based upon the cost of new entry.

New York has a mandatory monthly spot market auction through which LSEs trade capacity up to one month in advance. It also runs voluntary six-month strip and monthly auctions for each summer and winter "capability period". Capacity suppliers indicate the quantities and prices of their offers; and offers are accepted up to the point that the resulting supply curve meets the demand curve. LSEs are allowed to self-supply part or all of their capacity obligations. Capacity and capacity prices are differentiated by zone.

PJM has a mandatory centralized capacity market through which LSEs trade capacity up to three years in advance and in which new capacity can obtain guaranteed prices for up to three years. A Base Residual Auction (BRA) is held for a delivery year three years in the future. To allow market participants to make adjustments in their capacity resources by selling excess capacity or purchasing additional amounts to make up capacity deficiencies, three additional auctions may be held for each delivery year, occurring twenty, ten, and three months, respectively, prior to the delivery year.[49] The BRA determines the capacity price based upon a mathematical optimization program that finds the intersection point of capacity supply offers, and an administratively determined, downward sloping "capacity demand curve." The

[49] The three additional capacity auctions allow LSEs to adjust their capacity purchases to changing circumstances. Also, a conditional incremental auction may be held if a need to procure additional capacity results from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.

optimization considers deliverability constraints that define capacity pricing zones. In general, LSEs are allowed to self-supply only capacity that clears the centralized market.[50,51]

Figure 4 shows samples of the capacity demand curves used by the three eastern RTOs. The curves for the New York ISO and PJM begin at high capacity price levels when reserve margins are very low, then fall continuously as reserve margins rise, finally reaching zero prices at high reserve levels. The downward slope of these curves reflects the usual economic fact that the value of a good falls as it becomes more abundant. The curve for ISO New England, by contrast, begins at a high price level but then suddenly drops (vertically) to a low but positive floor price level at a threshold reserve level. The downward-sloping demand curve approach of ISO New England, the New York ISO, and PJM leads to less volatile capacity prices than would a vertical demand curve approach, as the former has price gradually change with reserve margins while the latter has price suddenly change at the threshold reserve level.[52]

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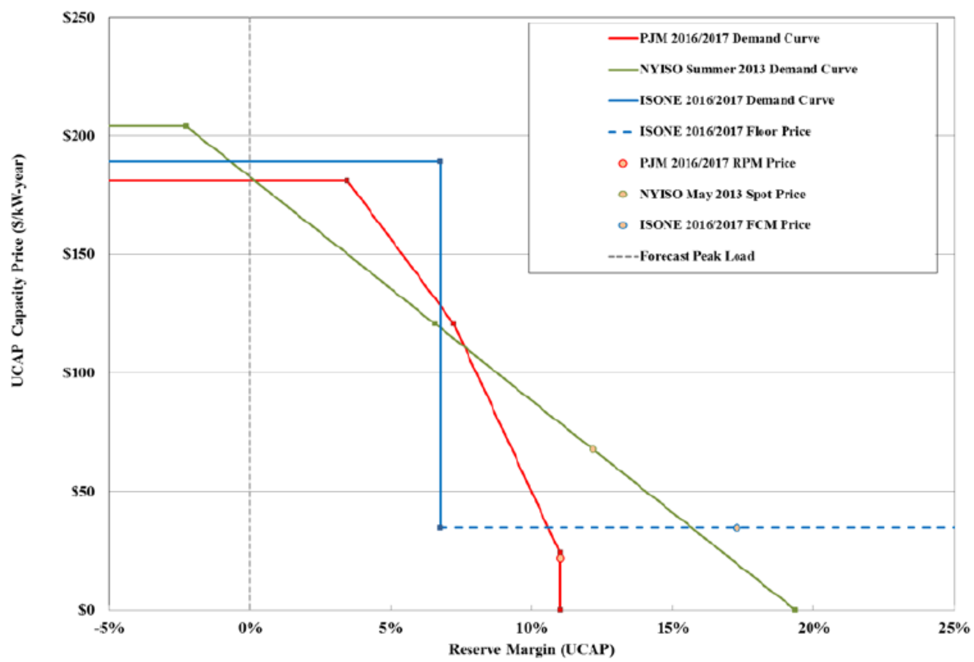
[50] LSEs can opt out of PJM's mandatory capacity market and self-supply all of their capacity on stringent terms that are cost-effective for only very large LSEs with very large resource portfolios.

[51] Federal Energy Regulatory Commission, 143 FERC ¶61,090 (2013), PJM Interconnection LLC, *Order Conditionally Accepting in Part, and Rejecting In Part Proposed Tariff Provisions, Subject to Conditions*, May 2, 2013.

[52] ISO New England and the New England Power Pool (NEPOOL) recently replaced its fixed capacity requirement (i.e., vertical demand curve) with an administratively determined, downward-sloping demand curve. See FERC, *ISO New England Inc., New England Power Pool Participants* Committee, Docket No. ER14-1639-000, April 1, 2014.

Figure 4
Sample Demand Curves for PJM, New York ISO, and ISO NE, 2016/2017 Delivery[53]



The maximum price when capacity falls short of the target is defined in all three RTOs in relation to the Cost of New Entry (CONE). CONE is defined as the annualized capacity cost of a new peaking plant. As illustrated in Figure 4, all three RTOs have set their maximum prices in the neighborhood of $200 per kW-year for the 2016/17 delivery year. All three RTOs set the maximum price at 1.5 times their estimates of CONE net of revenue earned from the energy and ancillary services markets as adjusted for forced outage rates (adjusted net CONE). The downward-sloping segments of the demand curves for New York ISO and PJM are defined by their reserve targets and various multiples of CONE, again adjusted for forced outage rates.

In traditionally regulated regions, "capacity" is defined differently than in RTO regions. While "capacity" in RTO regions is steel in the ground or qualifying demand-side resources, "capacity" in traditionally regulated regions is a call option that gives the buyer the right to purchase power at specified terms under particular conditions. The prices of capacity in traditionally regulated regions are therefore determined by buyers' demand for optional power that meets their reliability needs and by the cost and availability of sellers' resources to meet their needs. The capacity development process in traditionally regulated regions provides incentives for resource investment to the extent that sales of capacity add to the recovery of investment costs.

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[53] Federal Energy Regulatory Commission, *Centralized Capacity Market Design Elements*, Commission Staff Report, Docket No. AD13-7-000, August 23, 2013, Figure 2, p.6.

Although the word "chopper" can refer to motorcycles as well as helicopters, one would not suppose that the price of one kind of "chopper" bears any resemblance to the price of the other kind of "chopper." Similarly, because "capacity" is such a very different product in traditionally regulated regions than in RTO regions, and because the determinants of demand and supply for "capacity" are so different in these two types of regions, one should not expect that the prices of capacity are comparable between the two types of regions.

4.2.3. Market Power Mitigation

Market power can be exercised in capacity markets if and when participants can profitably manipulate capacity prices. A capacity seller that has resources in excess of its own requirements may be able to profit from withholding capacity from the market and thereby raising the prices at which they sell their excess. A capacity buyer that is deficient in resources may be able to profit by procuring subsidized resources and thereby reducing the market prices at which they must purchase resources to cure their deficiency; though some controversy has been generated by the strangeness of accusing participants of wrongdoing for procuring resources that meet their own needs.

Market power can be problematic in short-term capacity markets because of the insensitivity of supply to price: most resources that will be available a few years from now have already been built or at least have significant sunk costs that cannot be avoided by a decision to withhold capacity from the market; so, except in cases of retirement, the resources will be available regardless of the capacity price. The consequence of this insensitivity is that small changes in supply can have large impacts on short-term capacity prices. The price impacts are particularly great if the RTO's administratively determined demand curve is vertical, which means that the RTO requires a particular quantity of capacity regardless of price. Consequently, New York ISO and PJM have attempted to mitigate the price impacts of supply changes by incorporating a downward-slope into their administratively determined demand curves, which has the effect of reducing the profitability of exercising market power.

The RTOs have a variety of tests for market power. The tests for supplier market power variously seek to determine if there will be a shortage without the capacity of certain suppliers, or if certain combinations of suppliers have large market shares, or if a supplier's costs differ substantially from its offer price. The tests for buyer market power require that a supplier justify a low bid (below a minimum offer price) with cost data under certain circumstances.

The three eastern RTOs have similar market power mitigation rules. PJM, for example, has explicit rules that define the must-offer requirement for capacity, structural market power, and offer caps based on the marginal cost of capacity. These rules incorporate flexible criteria for competitive offers by new entrants or by entrants that may have an incentive to exercise monopsony power. Demand-side resources and Energy Efficiency resources may be offered directly into the capacity auctions and receive the clearing price without mitigation.

Market power mitigation can affect resource investments in a few ways. First, supply-side mitigation can induce capacity owners to offer all their capacity to the market, thereby increasing supply; though by holding down capacity prices, it might discourage new investment.

Second, buyer-side mitigation can dissuade resource-deficient LSEs from investing in new capacity; though by increasing capacity prices, it might encourage new investment by others. Third, market power mitigation may be implemented in ways that support or undermine state renewable resource policies or state resource planning processes.

Market power is not a problem in long-term capacity markets – that is, for capacity that is to be available more than a few years from the present – because buyers have the ability to build (or subscribe to) new capacity in this longer time frame. Consequently, capacity market power evaluation and mitigation occurs only in the context of RTOs' short-term capacity markets.

4.2.4. Strengths and Weaknesses of the Price Determination Methods

The main strength of the centralized capacity market price determination processes of the eastern RTOs lies in price transparency and liquidity of the markets. In addition, the downward-sloping demand curves used by New York ISO and PJM mitigate the volatility of capacity market clearing prices that are experienced under a vertical demand curve design, which also helps mitigate market power.

The price-setting methods of the eastern RTOs have several important weaknesses. First, the assumptions and estimates that underlie the determination of the demand curves are critical to price determination; and yet these assumptions and estimates, including those about the slope of the demand curve and CONE, have often been controversial. Moreover, some of the controversial estimates must be revised regularly, leading to regular repetition of the controversies. The controversies can be keen because the assumptions and estimates can have significant effects on the amounts of capacity procured and the prices of capacity.

Second, the physical and design characteristics of the eastern RTO's capacity markets can make them prone to exercises of market power. This susceptibility to market power arises from the physical limits that transmission places on capacity deliverability among zones and the steepness of the demand curves.

Third, in addition to fostering market power, transmission deliverability issues lead to zonal capacity markets of relatively small size, which decreases liquidity and increases the volatility of the zonal capacity prices. Furthermore, power system configurations change over time, even from year to year; so that the definitions of capacity zones must change over time. The consequence of the decreased liquidity, increased volatility, and shifting zonal definitions is to increase the uncertainty about future capacity prices and thereby increase the cost of capacity investment.

Fourth, the eastern RTOs try to treat heterogeneous resources as a homogeneous product. Consequently, they struggle, with limited success, to find ways to give comparable treatment to resources (e.g., fossil-fuel versus intermittent versus demand-side, existing versus planned, unlimited dispatchability versus limited dispatchability versus no dispatchability, flexible versus inflexible) that have very different operating and availability characteristics.

Fifth, the RTOs' centralized capacity markets make unrealistic assumptions about the relationship of capacity prices to capacity cost. The basic assumption is that the capacity prices should generally reflect the levelized cost of pure peaking capacity, which is why CONE is defined as the levelized annualized capacity cost of a new peaking plant. In addition to the various problems with the ways that CONE is quantified and annualized, however, there is little or no reason for anyone to offer capacity to the market at CONE or even at their own levelized annualized cost. Existing resources will always offer capacity at their opportunity cost of remaining in service, which is zero for most plants and a low figure for most of the rest. New resources will offer capacity at prices that depend upon their forecasts of market conditions over their whole lives, without the unrealistic assumption (explicit in levelization) that they must recover the same amount of capacity cost in every year. In the words of one prominent advocate of capacity markets,

> …the investor's projections of capacity prices for the remaining life of the new unit are vastly more important that the clearing price in the initial year in which the resource is cleared… [I]nvestors' decisions [to invest] will be principally governed by either expectations of future capacity prices beyond the initial auction or on a bilateral forward capacity contract that locks in a number of years of capacity revenues… For example, assume a unit has a net CONE over 30 years equal to $90 per kW-Year. It is unlikely that the new resource would be offered in a forward procurement market at close to $90 per kW-Year. If the investor has already made the decision to enter based on its projections of capacity prices over the next 30 years or the fact that it has signed a long-term bilateral contract, then the investor would likely submit offers well below $90 per kW-Year to ensure its offer clears. If the investor has not already made the decision to enter and expects that capacity prices are likely to fluctuate below $90 per kW-Year over the next 30 years (as surplus capacity levels rise and fall), then the investor would likely submit its offer at a price much higher than $90 per kW-Year.[54]

But in spite of the fact that no resource can reasonably be expected to base its offer price on CONE or even on its own levelized costs, the RTOs' capacity demand curves and their buyer-side market power mitigation are both based upon CONE.

4.3. Traditionally Regulated Regions

In traditionally regulated regions, resource requirements are determined by a combination of NERC, the relevant regional reliability entities, federal and state requirements, and utilities implementation of good utility practices. Each LSE (possibly in the context of a state proceeding) forecasts its resources and loads and determines whether it needs additional resources to meet it capacity obligation or whether it has excess resources to offer to other parties. If it needs additional resources, it either invests in generation capacity on its own, invests in joint ownership arrangements with other LSEs, enters into competitively determined

[54] *Post-Technical Conference Comments of Potomac Economics Ltd. New York ISO Market Monitoring Unit*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, before the Federal Energy Regulatory Commission, Docket No. AD13-7-000, January 8, 2014, p. 19.

bilateral contracts to purchase the output of capacity from other parties, or undertakes some combination of the foregoing options.

The decision about whether to "build" or "buy" comes down to an economic assessment of the options, which will also include consideration of fuel mix, capacity lumpiness, expected rate of load growth, and a host of other factors including regulatory policy (such as those regarding competitive bidding requirements, renewable resources and environmental regulations). When the "buy" option is pursued, the utility typically issues a request for proposals to supply the needed incremental capacity, which also typically includes energy. Contract length can vary from only a couple of years to very long term (e.g., 20 years). Bids from interested suppliers are evaluated on terms that go beyond price, including deliverability, generator characteristics, and technology type. Thus acquisition of capacity in bilateral markets is subject to competition, and the prices of capacity in bilateral markets are determined by a competitive process.

The main strengths of capacity price determination in traditionally regulated regions are that prices depend upon the real demands of buyers and upon the actually available supplies of sellers, and that prices are determined through a competitive process, albeit often scrutinized by state utility regulators. These capacity prices reflect real market value. Because the capacity markets in traditionally regulated regions are not limited to a homogeneous capacity product, buyers and sellers can take into account the particular operational and other characteristics of the particular resources involved; and the capacity price can reflect those characteristics.

The main weakness of the price-setting process in traditionally regulated regions is that prices are not transparent, so it is possible that the most efficient capacity trades are sometimes unrecognized. Related to the lack of transparency is a relative lack of liquidity, which can cause prices to be volatile. The impacts of volatility on customers are muted, however, since the volatility affects only incremental capacity needs while the bulk of the utility's capacity costs are fixed based on prior years' commitments.

5. RESOURCE OUTCOMES

How well has each capacity market approach done at assuring reliability at least cost? Are there significant differences among the approaches in their reliability outcomes? Are there significant differences among the approaches in their costs?

This section assesses resource outcomes primarily in terms of reliability outcomes, reliability indicators (like reserve margins), achievement of public policy goals (like expansion of renewable resources), capacity prices, and consumer costs.

5.1. Reliability

Power system reliability is measured by the MWh magnitude, the geographic extent, and the time duration of customer service outages. In principle, reliability should be the gold standard for judging resource outcomes: adequate resources should result in relatively reliable power systems, while inadequate resources should result in relatively unreliable power systems. In practice, however, the overwhelming majority of customer service outages are due to failure of local, low-voltage distribution systems, usually caused by adverse weather conditions; and most of the remaining outages are caused by bulk power transmission failures. By contrast, our concern in this report is with those outages that occur at the transmission level due to insufficient capacity resources, which are a tiny percentage of all outages experienced by customers.

Unfortunately, it is not possible to easily separate outages due to insufficient capacity resources from those due to other causes. While transmission failures due to lightning or trees are among these other causes, system operator error is the most common cause. Operator errors include:

- overestimation of generator availability;
- overestimation of generators' dynamic reactive output;
- inability to visualize events over the entire power system;
- failure to ensure that system operation was within safe limits;
- lack of coordination on system protection;
- ineffective communication between system operators and resource operators;
- lack of "safety nets;" and
- inadequate training of personnel.

Consider, for example, the following major North American outages of the past half century:[55]

- **November 9, 1965, Northeastern U.S.** System operators lacked adequate information about system conditions, and were unaware of the operating set point of the relay that started the cascading outages.
- **July 13, 1977, New York City.** Lightning struck and tripped out two transmission lines on a common tower, and separated New York City from the surrounding power systems. A bent contact on a relay contributed to the collapse.
- **December 22, 1982, West Coast.** High winds knocked over a transmission tower, which fell onto an adjacent tower, taking out of service the two transmission lines held up by the two towers. Contingency planning failed to consider the power flows caused by this event. A control signal was delayed by a communications failure. System operators lacked sufficient information to identify appropriate action.
- **July 2-3, 1996, West Coast.** Due to a vegetation maintenance failure, a sagging transmission line contacted a tree and tripped out. A protective relay on a parallel line incorrectly tripped out.
- **August 10, 1996, West Coast.** Due to high temperatures, three transmission lines sagged, contacted untrimmed trees, and trip out. Because of insufficient contingency

[55] JTF 031119 Report, Chapter 6.

planning, system operators were unaware, for the next hour, that the system was in an insecure state.

- **June 25, 1998, Ontario and North Central U.S.** Lightning struck and tripped out two 345-kV transmission lines, which led to overloading of lower-voltage lines. Relays took these lower-voltage lines out of service. This cascading removal of lines from service eventually separated the entire northern MAPP Region was separated from the Eastern Interconnection.
- **July 1999, Northeastern U.S.** PJM's load was 5,000 MW higher than forecast, resulting in a loads exceeding available resources.
- **August 14, 2003, Northeastern U.S and Ontario.** Beginning with a vegetation maintenance failure, MISO system operators were literally out to lunch. They lacked adequate system information, failed to operate the system within secure limits, failed to identify emergency conditions, failed to communicate with neighboring systems, lacked sufficient regional and interregional visibility of the power system, had a dysfunctional SCADA/EMS system, lacked adequate backup for their SCADA/EMS system, and suffered inadequate operator training.
- **September 8, 2011, Southern California.** A 500-kilovolt east-west transmission line in California, the Hassayampa-North Gila line, failed because a technician skipped several steps as he tried to isolate some transmission equipment for testing. His actions led to a short circuit and a shutdown of the line. The blackout's scope could have been limited if operators had been trained to intentionally cut off some areas to prevent a cascade. As with the Eastern blackout in 2003, however, system operators had poor knowledge of what was happening in neighboring systems, which prevented them from taking proper action until it was too late.[56]

Thus, with the exception of the 1999 Northeast blackout, the major North American outages of the past half century have not been due to inadequate resources. Consequently, reliability statistics reveal little about resource adequacy.

5.2. Resource Additions and Reserves

The most relevant measure of resource adequacy is arguably reserve margins, which are the amounts by which resources exceed loads. The patterns of resource additions over time directly affect reserve margins and indicate whether investment has been sufficient and will be sufficient to maintain reserve margins. Consequently, this section presents statistics on capacity additions and reserve margins.

[56] FERC and NERC Staffs, *Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations*, April 2012.

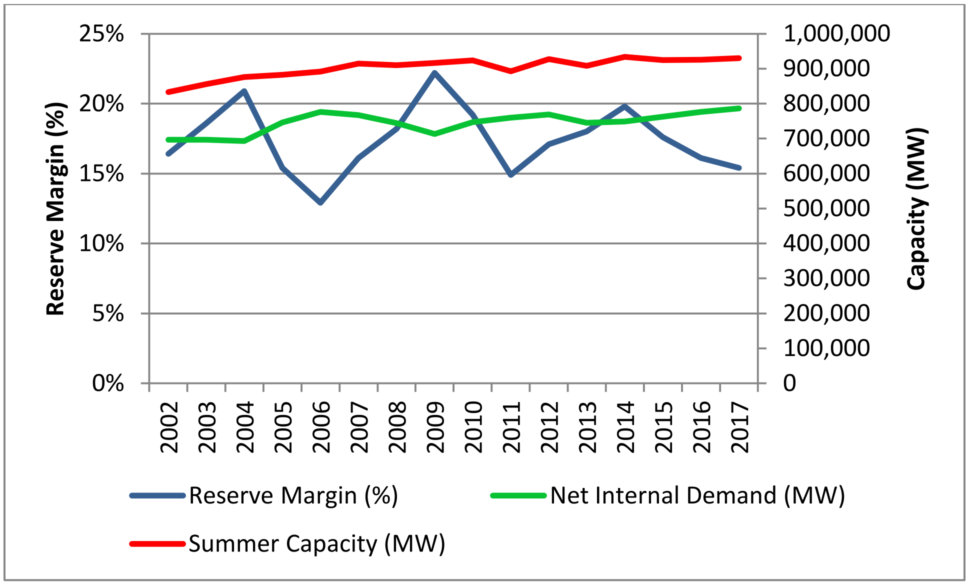
5.2.1. Overview of U.S. Capacity Resources

Figure 5 shows how total resources (including generation and demand-side resources), total annual peak loads, and reserve margins have changed (and are projected to change) for the entire U.S. over the period 2002-2017. The figure looks at summer peaks rather than winter peaks because, for the U.S. as a whole, summer peaks are about 8% higher than winter peaks; so summer reliability issues tend to be more critical than winter reliability issues.[57] The figure shows that the U.S. summer resource capacity has exceeded net internal demand by approximately 15% or more over the last 12 years and is projected to continue that relationship through at least 2017.

Resource additions and reserve margins are the consequence of many factors, of which market design is only one. Other major factors include, for example, regulatory rules, legal requirements for renewable resources, fuel prices, and general economic conditions. Nonetheless, this section looks at traditionally regulated regions separately from RTO regions in an effort to see if different market structures lead to any obvious differences in resource addition or reserve margin outcomes.

[57] Perhaps the one exception to that has been the most recent 2013/2014 winter, which was characterized by the "polar vortex" described in various parts of this report.

Figure 5
Resources, Peak Loads, and Reserve Margins for the U.S., Summer 2002-2017[58]

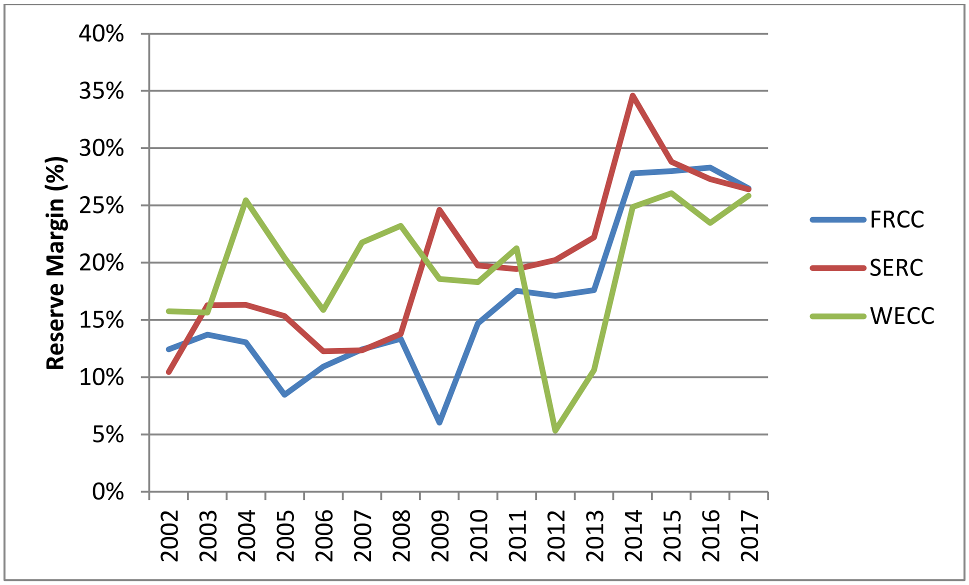


5.2.2. Traditionally Regulated Regions with Vertically Integrated Utilities

Figure 6 shows summer peak reserve margins for three traditionally regulated regions, namely Florida (FRCC), the southeastern U.S. (SERC), and the western interconnection excluding California (WECC). Years through 2012 are actual historical results, while years beginning in 2013 are forecasts. Overall, reserve margins in WECC have been most volatile; SERC's margins have been consistently higher than FRCC's margins; and SERC's margins have been consistently above the 10% level. In all cases, the reserve margins do not reflect demand-side capacity.

[58] U.S. Energy Information Administration, Form EIA-411, *Coordinated Bulk Power Supply and Demand Program Report*. http://www.eia.gov/electricity/data.cfm#demand, "Summer net internal demand, capacity resources, and capacity margins, 2001-2011 actual" and "Summer net internal demand, capacity resources, and capacity margins, 2011 actual, 2012-2016 projected" (Form EIA-411). "Net Internal Demand" represents the system demand that is planned by the electric power industry`s reliability authority and is equal to Internal Demand less Direct Control Load Management and Interruptible Demand. "Summer Capacity" represents utility- and non-utility-owned generating capacity that exists (as part of the historical record) or is in various stages of planning or construction (as part of the project capacity), less inoperable capacity, plus planned capacity purchases from other resources, less planned capacity sales. "Cap Margin" represents the amount of unused available capability of an electric power system at peak load as a percentage of capacity resources. These definitions apply to all subsequent figures. The Summer peak period is defined to begin on June 1 and extends through September 30.

Figure 6
Summer Peak Reserve Margins (%) of Non-RTO Regions[59]



In FRCC, reserve margins bounced around throughout most of the past decade, hit a low of 6% in 2009, and have been (and are projected to be) in the 14% to 27% range since 2010. The low reserves occurred in 2009 because, in spite of the 2008-2009 financial crisis, FRCC loads hit a high in that year at the same time that there happened to be resource retirements. The stability of reserve margins from 2011 onward reflects the actual and forecast stability of total capacity and peak loads beginning in 2011.

In SERC, reserve margins were in the 10% to 16% range through 2008. Since the onset of the financial crisis of 2008-2009, reserve margins have been (and are projected to be) of 20% to 35%. This occurred, in part, because SERC's peak load during the years 2005-2009 was consistently over 186 GW, but has been (and is forecast to be) only about 160 GW from 2010 onward. Not coincidentally, SERC's capacity peaked in 2009, since which time retirements reduced capacity by 20%, with future capacity forecast to be flat.

In WECC (excluding California), reserve margins generally have been maintained at or above the NERC reference level with the exception of 2012, when capacity reached its low point while peak load jumped 9%. The recent and forecast jump in reserve margins is due largely to an

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[59] WECC data are obtained from Energy Information Administration, Table 8.8.A, "Summer Net Internal Demand, Capacity Resources, and Capacity Margins by North American Electric Reliability Assessment Areas 2002-2012, Actual", and Table 8.8.B, "Summer Net Internal Demand, Capacity Resources, and Capacity Margins by North American Electric Reliability Corporation Assessment Areas, 2012 Actual, 2013-2017 Projected", both available at http://www.eia.gov/electricity/annual/. The original source is Form EIA-411. Projected reserve margins for FRCC and SERC were obtained from North American Electric Reliability Corporation, *2013 Long-Term Resource Assessment*, December 2013.

expected 35 GW increase in supply-side capacity, split about evenly between gas-fired, wind, and solar generation.

5.2.3. Centralized Markets of Regional Transmission Operators

Figure 7 shows that the RTOs shared a common reserve margin trend up until the wake of the financial crisis of 2008-2009, since which time their paths have diverged. The RTOs generally had excess reserves in 2002 that were left over from the investment binge of the late 1990s, when electricity industry deregulation gave investors some of the irrational exuberance for generation investments as they had for stock market investments. Rising loads in California, ERCOT, and SPP helped to bring down their reserve margins in the years through 2006, while their capacity was basically flat. The years 2006-2009 saw rising reserve margins as loads generally declined (with Texas being the exception) while capacity was flat to rising.

Since 2009, the RTOs' reserve margins have taken (and are forecast to take) divergent paths that are best explained by looking at each RTO.

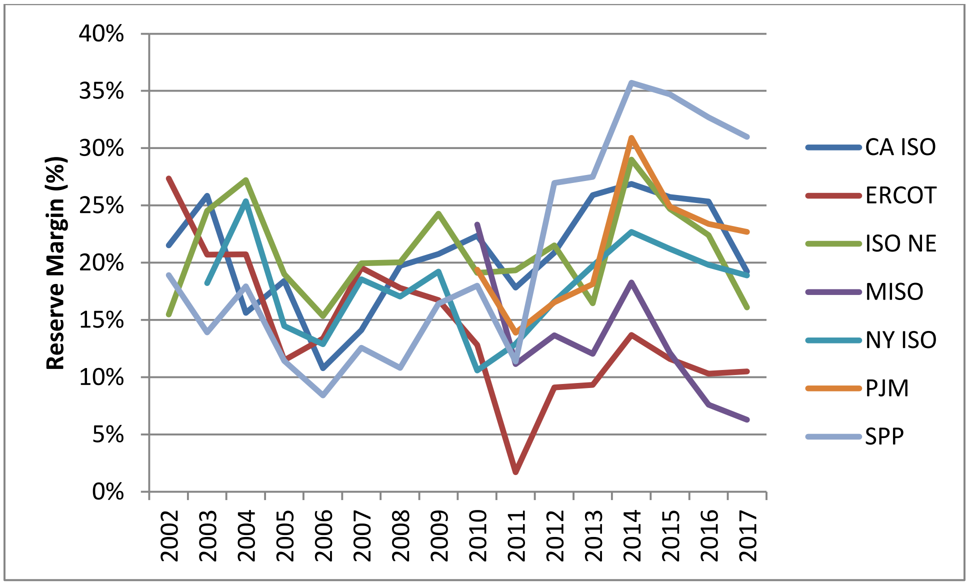
In California, since the shortages of the 2000-2001 crisis, reserve margins generally have been maintained at or above the NERC and CPUC's target reference level of 15% and are anticipated to remain well above the target over the next four years. A significant driver in the increase in reserve margin over the next few years is California's renewable portfolio standard (RPS), which requires that 33% of the state's annual electrical energy be obtained from renewable resources by 2020. On the other hand, environmental restrictions on once-through cooled generation[60] are expected to force retirement of about 13,000 MW of older capacity by 2020. Another major reduction in non-renewable resource capacity will occur later this decade with the retirement of the 2,100 MW San Onofre nuclear plant. The combination of these factors is forecast to reduce reserves in 2017 and beyond.

To deal with retirements as well as the reliability and resource adequacy issues that will accompany the substantial growth of intermittent generation, the California ISO proposed a special compensation mechanism for critical generation resources that might otherwise retire. FERC rejected California ISO's special compensation mechanism as "an ineffective out-of-market solution" and has requested that the California ISO instead develop a market-based mechanism to achieve its resource adequacy goals.[61]

[60] Once-through cooled generation uses water's cooling capacity only a single time before discharging the water as waste. It thus withdraws and promptly returns large volumes of warmed water.

[61] Federal Energy Regulatory Commission, *Order On Tariff Revisions*, 142 FERC ¶ 61,248, Docket No. ER13-550-000, March 29, 2013.

Figure 7
Summer Peak Reserve Margins (%) of RTO Regions[62]



In ERCOT, reserve margins have been eroding since 2002, when they were well above 25%. Reserve margins are expected to remain well below the NERC target reference level of 13.75% for the next several years. According to NERC:

> The depleting Reserve Margin in ERCOT is due to generation resource additions not having kept pace with the higher than normal load growth experienced in recent years. The generation market in ERCOT is unregulated and generators

[62] Historical reserve margins for ERCOT, MISO, PJM, and SPP were obtained from Energy Information Administration, Table 8.8.A, "Summer Net Internal Demand, Capacity Resources, and Capacity Margins by North American Electric Reliability Assessment Areas 2002-2012, Actual", http://www.eia.gov/electricity/annual/. Projected reserve margins for ERCOT, MISO, PJM, and SPP are "Anticipated Reserve Margins" obtained from North American Electric Reliability Corporation, *2013 Long-Term Reliability Assessment*, December 2013, pp. 20, 123, 142, and 149. California ISO reserve margins are based on "California Peak Load History, 1998 – 2013", http://www.caiso.com/Documents/CaliforniaISOPeakLoadHistory.pdf. California ISO capacity for 2005-2013 is from "Cal ISO Summer Load and Resource Assessment Report" various years, obtained at https://www.caiso.com/planning/Pages/ReportsBulletins/Default.aspx. California ISO projected reserve margins for 2014-2017 are from California Public Utility Commission, *CPUC Briefing Paper: A Review of Current Issues with Long-Term Resource Adequacy*, February 20, 2013, Appendix B: 2012 LTPP Base Scenario (2012-2022), obtained at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M040/K642/40642804.PDF. Historical reserve margins for ISO New England are based on ISO New England, *2013 CELT Report*, obtained at http://www.iso-ne.com/trans/celt/report/. Projected reserve margins for ISO New England are "Anticipated Reserve Margins" from North American Electric Reliability Corporation, *2013 Long-Term Reliability Assessment*, p. 91. Historical reserve margins for New York ISO were obtained from "NY ISO Load & Capacity Data", various years. Projected reserve margins for New York ISO are "Anticipated Reserve Margins" obtained from North American Electric Reliability Corporation, *2013 Long-Term Reliability Assessment*, December 2013, p. 101.

> make resource decisions based on market dynamics. Generation investors state that a combination of lack of long-term contracting with buyers, low market heat rates, and low gas prices are hindering decisions to build new generation. For its part, the PUCT and ERCOT are working through to study, and facilitate revisions to, market protocols and pricing rules to bolster the reserve margin. To incent new generator construction, improvements such as increases in system-wide Energy Offer caps, rising of Energy Offer floors, and adjustments to Emergency Response Service to include distributed generator participation, are among the results so far. Several proposed initiatives focus on DR resources, such as revising market rules to stimulate greater participation of weather-sensitive loads in the Emergency Response Service program. The PUCT has directed ERCOT to draft rules for incorporation of an interim energy market funding solution called the Operating Reserve Demand Curve (ORDC). The PUCT will continue efforts regarding possible setting of a mandated reserve margin level in the ERCOT region.[63]

In New England, reserve margins have consistently exceeded the target of 15% over the past decade, and are expected to fall to the target level by 2017. The forecast for 2017 appears to be a statistical quirk, however, due to exclusion of Capacity Supply Obligations (CSOs) in ISO New England's forecast of capacity in 2017. Correcting for that statistical quirk, reserve margins will likely remain in the neighborhood of 20%.

In MISO, there is forecast to be a dramatic decline in reserve margins for MISO from 23% in 2010 down to 6.3% in 2017, well below the target level of 14.2%. Peak demand has already fallen and is forecast to remain relatively flat over the next several years, while capacity has fallen more sharply as generating plant is retired, particularly in response to new environmental rules. According to NERC:

> Based on MISO's current awareness of projected retirements and the resource plans of its membership, Planning Reserve Margins will erode over the course of the next couple of years and will not meet the 14.2 percent requirement. The impacts of environmental regulations and economic factors contribute to a potential shortfall of 6,750 MW, or a 7.0 percent Anticipated Reserve Margin… by summer 2016. Accordingly, existing-certain resources are projected to be reduced by 10,382 MW due to retirement and suspended operation.[64]

In New York, just over half of the investment during the period 2000-2012 occurred in the three years 2004–2006. Since 2002, reserve margins have generally remained above the NERC reference level of 15%, with the exception of 2010. The New York ISO's own installed reserve margin target is 17% (set by the NYSRC) and the forecast indicates the region will exceed that

[63] North American Electric Reliability Corporation, *2013 Long-Term Resource Assessment*, December 2013, p. 150. Note that low market heat rates and low gas prices lead to low prices for electrical energy.

[64] North American Electric Reliability Corporation, *2013 Long-Term Resource Assessment*, December 2013, p. 54.

target through at least 2017. The stable reserve margins projected over the next few years are due to moderate expected growth in peak load coupled with few planned generator retirements. However, retirement of the Indian Point Nuclear Power Plant, in 2015 or thereafter, would lead to immediate violations of the NYSRC's reserve margin criteria.

In PJM, reserve margins have generally held above PJM's planning reserve target of about 15.5%, but are projected to decline below this level after 2014. With peak demand growth expected at just over 1% per year and demand-side management resource capacity expected to remain fairly constant, the principal driver of the decay in reserve margins is the significant retirement of fossil-fired generation – 13,000 MW (or about 7% of the existing capacity) composed of 9,700 MW of coal plants, 2,000 MW of gas-fired plants, and 1,300 MW of oil-fired generation.[65]

In SPP, reserve margins during the mid-2000s dropped below the planning reserve target of 13.6%, but since have climbed to acceptable levels, rising abruptly in 2012 to 27%. SPP's reserve margins are expected to remain above the NERC reference target for the foreseeable future as a result of moderate load growth and a modest 400 MW of retirements.[66]

5.2.4. Summary of Findings

Baseline forecasts usually reflect an assumption that the future world will be normal – which it usually is on average, but which it often is not in individual cases. With the exceptions of ERCOT and MISO, whose reserve margins are projected to decline to levels well below the NERC target margins, the NERC regional reliability entities and the RTOs project adequate reserve margins for the foreseeable future. However, reserve margins in all regions are projected to decline over the next decade, primarily because the capacity of the large number of retirements of coal-fired plants will exceed the capacity of the new plants (gas-fired and renewable for the most part) coming into service.

5.3. Resource Mix

The mix of capacity resources can have major impacts on power system reliability, for several reasons. First, supplies of particular resources can become constrained due to weather conditions, transportation bottlenecks (as happened with natural gas supplies and coal supplies this past winter of 2013-2014), or production problems; so over-reliance upon a single resource technology can have adverse reliability or cost impacts. Second, demand-side capacity resources are an innovation that is not entirely out of the testing stage: in the long run, such resources may or may not prove as reliable as traditional supply-side resources. Third, intermittent renewable resources (i.e., wind and solar) pose new challenges for maintaining power system security; and these challenges will grow disproportionately quickly as the market share of these resources grows.

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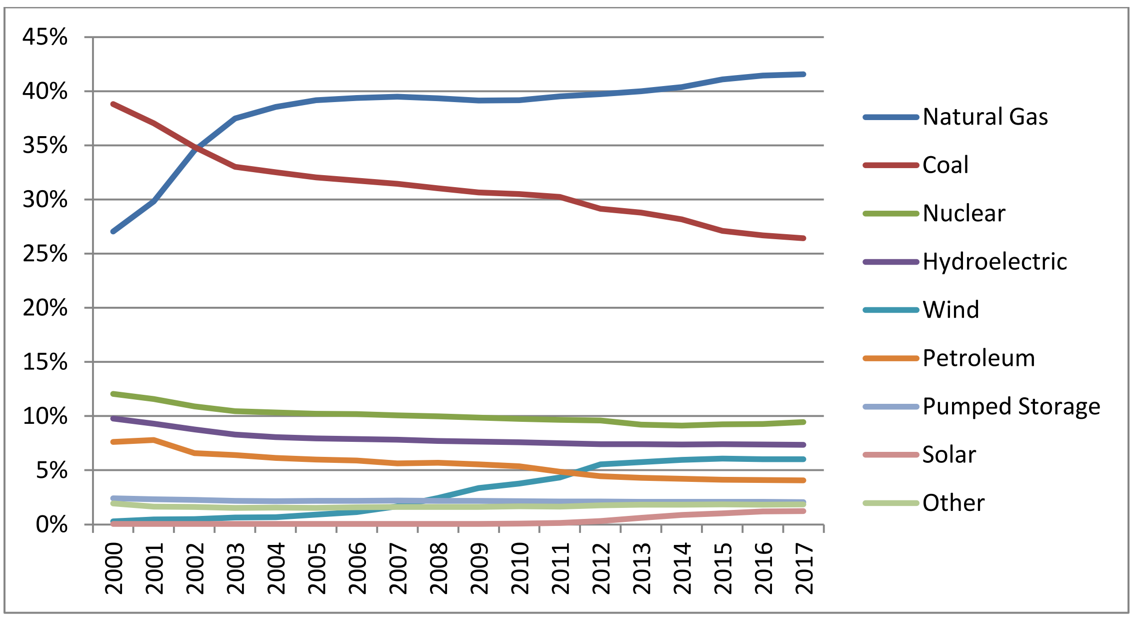
[65] North American Electric Reliability Corporation, *2013 Long-Term Resource Assessment*, December 2013, p. 124.

[66] North American Electric Reliability Corporation, *2013 Long-Term Resource Assessment*, December 2013, p. 143.

5.3.1. Overview of the U.S. Resource Capacity Mix

Figure 8 shows how, for the entire U.S., the resource capacity mix has evolved over the period 2000-2012 and is forecast to evolve over the period 2013-2017. The figure shows that, for the 2000-2017 period, coal and gas switch first and second places: coal drops from a 39% market share to a 26% market share, while gas rises from a 27% market share to a 42% market share. The other resource technologies have market shares that are generally 10% or less. The shares of nuclear, hydroelectric, petroleum, and pumped storage all gradually decline over the period, even though all but petroleum have more GWs of capacity in 2017 than in 2000. Meanwhile, the shares of wind and solar, which were near 0% in 2000, rise to 6% and 1%, respectively, in 2017. The overall story, then, is that gas, wind, and solar have been rising stars while petroleum is fading out.

Figure 8
U.S. Resource Mix, Shares of Summer Capacity, 2000-2017[67]



The changing market shares reflect changing economics and politics. Coal faces growing and particularly costly environmental restrictions, the uncertainty of greenhouse gas-related costs, and well organized environmental opposition, all of which make traditional coal-fired investments less attractive. Natural gas, by contrast, has enjoyed technological progress that has substantially increased potential gas supplies and significantly reduced gas costs, thus

[67] U.S. Energy Information Administration, "Planned generating capacity additions from new generators, by energy source, 2011-2015 December 12, 2013", Table 4.5; and "Existing Capacity by Energy Source, by producer, by state back to 2000", existcapacity_annual.xls, both obtained at http://www.eia.gov/electricity/data.cfm#gencapacity.

making gas-fired investments more attractive.[68] Petroleum has continued its long-term decline as oil-fired generation is generally replaced by cheaper and cleaner gas-fired generation. The progress made by wind and solar resources has partly been due to technological improvements that have reduced their costs but has mostly been due to substantial subsidies.[69]

5.3.2. Overview of Regional Capacity Resources

Figure 9 illustrates the fuel mix across the regions of the U.S. in 2011. The central (Mountain, West North Central, East North Central, South Atlantic, East South Central) and southeastern regions rely heavily on coal, whereas the northeastern regions (New England and Middle Atlantic) rely more heavily on a combination of nuclear and natural gas. The West South Central region relies heavily on a combination of coal and natural gas, while hydro and natural gas dominate in the Pacific Contiguous region.

Despite the abundance of coal and natural gas resources in the U.S., the fuel diversity displayed in Figure 9 may soon be altered significantly. The nation's generation fleet is experiencing a dramatic shift, spurred by low natural gas prices and a suite of new environmental regulations that are particularly adverse to coal use. This shift is expected to occur largely over the next five to seven years as natural gas prices are expected to remain low and recent environmental regulations are likely to accelerate the retirement of a significant portion of the nation's coal-fired power plants. In addition, pending regulations would prohibit the construction of new coal-fired power plants that do not have carbon capture and sequestration capabilities, effectively phasing out the use of new coal generation as a future resource in the United States.[70]

5.3.3. Renewable Energy Resources

Because of their relatively high costs, wind, solar, geothermal, and biomass resource investments have been heavily dependent upon public policy, particularly federal and state income tax subsidies and renewable portfolio mandates. As the subsidies have grown and (particularly) as the mandates have become more stringent, investment in these technologies has increased. Since 2000, this investment has been substantial and been concentrated on wind power. Renewable energy capacity grew at a 4.8% per annum compound rate from 2000 through 2012, nearly doubling during the period. In 2012, renewable power resources provided 56% of generating capacity additions, and constituted 14% of U.S. installed capacity

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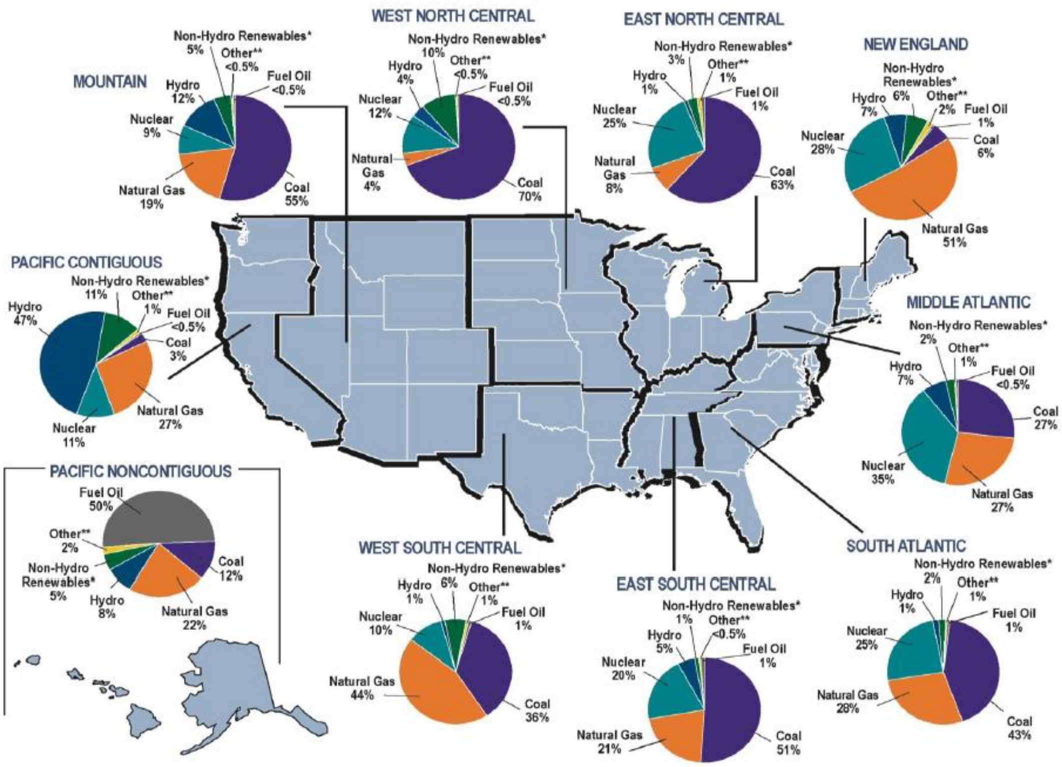
[68] The abundance of natural gas in the U.S. has created a strong lobby for increasing U.S. natural gas exports, which would be profitable due to high overseas natural gas prices and could improve the energy security of U.S. allies. Significant export of natural gas would put upward pressure on gas prices in the U.S. and could eventually make investment in gas-based capacity less economic.

[69] Section 5.6 reviews the cost trends that influence the resource mix.

[70] U.S. Environmental Protection Agency, *Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, Notice of Proposed Rulemaking*, 77 Fed. Reg. 22,392, April 13, 2012.

and 12% of generated electrical energy. Of the renewable resource generation in 2012, 55% was hydroelectric, 28% was wind, 11% was biomass, and solar and geothermal provided 3% each.[71] While wind, biomass, and geothermal generation will continue to grow, solar power is projected to have the largest future growth, in percentage terms, between now and 2040.

Figure 9
U.S. Regional Fuel Diversity, 2011[72]



The leading states for solar power investments (photovoltaic (PV) and concentrating solar power (CSP)) are mostly in the southwestern and southern states that have the best solar exposure. Similarly, the leading states for geothermal and hydroelectric resources tend to be those with the best geological conditions for these resources. But these are merely tendencies. What particularly drives the locations of investments are the public policies that support renewable power.[73] Not surprisingly, the ten states with the largest amounts of installed

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[71] U.S. Department of Energy, Renewable Energy and Energy Efficiency, *2012 Renewable Energy Data Book*, October 2013, pp. 17-18, http://www.nrel.gov/docs/fy14osti/60197.pdf.

[72] U.S. House of Representatives, The Committee on Energy and Commerce, *Memorandum, Subcommittee On Energy and Power Hearing*, March 4, 2013, Appendix, p. 4.

[73] U.S. Department of Energy, Renewable Energy and Energy Efficiency, 2012 Renewable Energy Data Book, October 2013, p. 31. Original sources: EIA, GEA, LBNL, SEIA/GTM, Larry Sherwood/IREC.

renewable capacity in 2012 are also states with renewable portfolio standards that mandate large amounts of installed renewable capacity by 2016. Table 2 lists these states, which together had about 61% of the total RE capacity in the country in 2012. Aside from Texas, the top five states rank high because of their significant hydro capacity. Texas, by contrast, rates high because of its huge investment in wind and solar, which can be attributed largely to the state's favorable geographic location.

Table 2
Relationships Between RPS Requirements and Renewable Investment
Top Ten Renewable Resource States in 2012, by Total RE[74]

State	2011 Installed Capacity	RE Target	Intermediate Target	2012 Installed RE Total	% of Installed Capacity	2012 Installed Wind + PV	% of Installed Capacity
WA	30,507	15% by 2020	3% by 2012	24,342	80%	2,827	9%
CA	68,295	33% by 2020	20% by 2014	22,508	33%	8,102	12%
TX	109,179	5,880 MW by 2015 (8.8% of 2012 Peak)	5256 MW by 2013	13,517	12%	12,354	11%
OR	14,535	Large Utils - 25% by 2025; Small Utils - 10%; Smallest Utils - 5%	5% by 2011	11,845	81%	3210	22%
NY	39,629	Overall target of 7% of incremental MWh by 2015 (equivalent to about 0.5673 of total load)	No interim goals	7,003	18%	1818	5%
IA	15,288	105 MW fixed (1.3% of 2012 Peak)	No interim goals	5,280	35%	5,134	34%
AZ	27,043	10.55% by 2025	No interim goals	4,108	15%	1,345	5%
OK	21,824	15% by 2015	No interim goals	3,699	17%	2,998	14%
Al	32,577	No explicit RPS	No interim goals	3,917	11%	1	< 1%
IL	43,830	25% by 2025	6% by 2012	3,803	9%	3,611	8%

Wind power has become a large share of RE, and the rankings in Table 2 reflect the rise of wind power. Back in 2000, when total U.S. wind capacity was only 2,578 MW, California had nearly two-thirds of the capacity. In 2012, when capacity was about 60,000 MW, Texas had taken the top spot and wind capacity was much more evenly spread among states. The southeastern U.S. is nearly devoid of wind resources, which is partly a reflection of the relatively poor wind conditions in that part of the country.[75] Iowa and Illinois now appear in the top five states ranked on total installed wind and PV capacity, which is a reflection of the relatively good

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[74] Installed capacity data are from U.S. Energy Information Administration, "Existing capacity by energy source, by producer, by state back to 2000," http://www.eia.gov/electricity/data.cfm#gencapacity. RE Target and Intermediate Target information are from Database of State Incentives for Renewable Energy (DESIRE), obtained at http://www.dsireusa.org/. RE capacity data are from U.S. Department of Energy, Energy Efficiency & Renewable Energy, 2012 Renewable Energy Data Book, http://www.nrel.gov/docs/fy14osti/60197.pdf.

[75] American Wind Energy Association, *AWEA U.S. Wind Industry Third Quarter 2013 Market Report,* October 31, 2013, p. 5.

conditions for location of wind installations. The top ten states possess about 69% of wind and solar capacity in the country.

Washington, Oregon, and California are all among the top five RE states because of their significant hydro capacity. Alabama likewise makes it into the top ten for overall RE because of its abundant hydro capacity, though it would rank among the bottom of the states on the basis of its wind and solar capacity.

5.3.4. Demand-Side Resources

Figure 10 summarizes the actual peak load reductions achieved through energy efficiency measures and load management over the period 2002 to 2012. During this eleven year period, peak load reductions achieved through demand-side management programs have nearly doubled, with energy efficiency growing at an 8.0% annual rate and load management growing at a 3.6% annual rate. These demand side resources were 2.5% of supply-side capacity in 2002 and 4.0% of supply-side capacity in 2012.

Figure 10 provides a projection of peak load reductions due to demand-side management programs over the period 2012 to 2023. The growth rates of demand resources are projected to fall to a 3.6% annual rate for energy efficiency and a 2.3% annual rate for load management. Nonetheless, this NERC projection has energy efficiency and load management programs together accounting for nearly 15% of non-coincident total internal demand for the peak summer season of 2023.

Figure 10
Estimated Demand-Side Management Load Reductions by Program Type, 2002-2012[76]

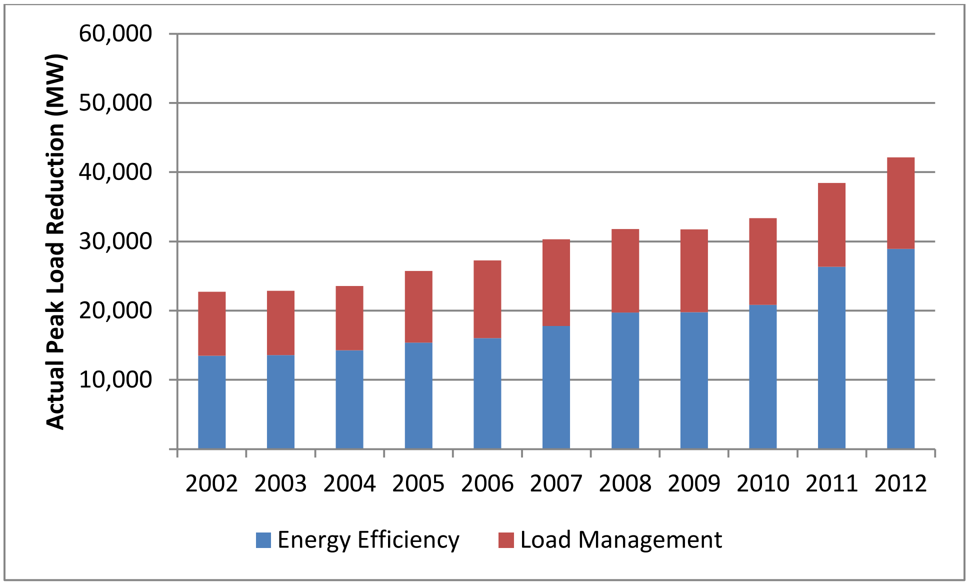
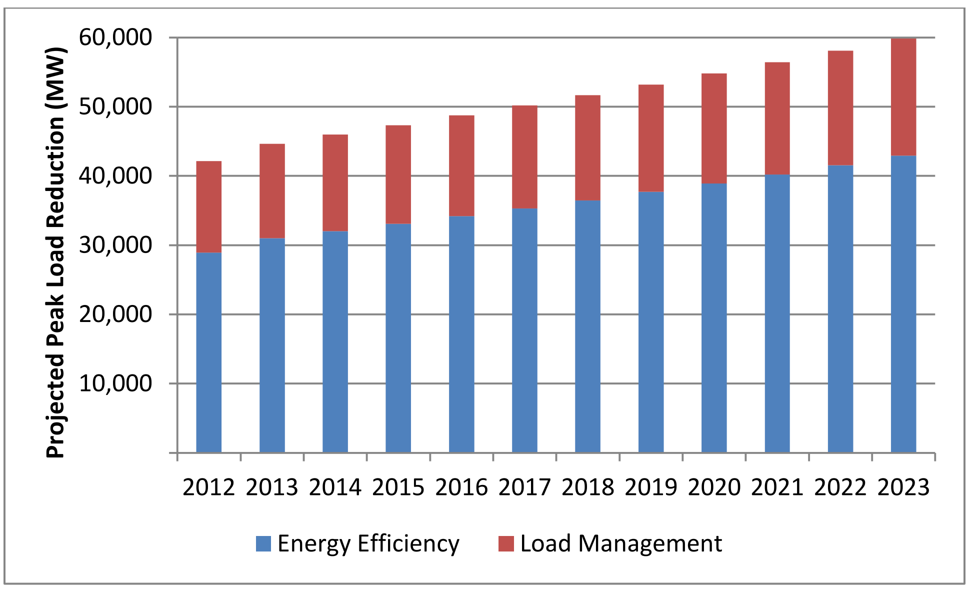


Figure 11
Projected Demand-Side Management Load Reductions by Program Type, 2012-2023[77]



[76] Energy Information Administration, Electric Power Annual, 2012, Table 10.1, Demand-Side Management Annual Effects by Program Category, 2002 to 2012, obtained at http://www.eia.gov/electricity/annual/.

[77] Projections based on NERC, 2013 Long-Term Resource Assessment, pp. 8-9. NERC projects that available energy efficiency will increase by 11.9 GW and load management will increase by 3.3 GW between 2014 and 2023. This translates to a compound annual growth rates of 3% for energy efficiency and 2% for load management.

In the eastern RTO capacity market auctions, large quantities of demand-side resources have been offered and cleared, which has caused the RTOs' capacity prices to drop substantially. In PJM, for example, about one-third of new capacity obtained through its Base Residual Auctions has been from demand-side resources.

Unfortunately, in at least some RTO markets, demand-side resources provide a lower quality of capacity than do supply-side resources. Andy Ott of PJM explains the limitations of the demand-side resources available to PJM:

> …almost all demand resources are specifying two-hour notice requirements and emergency-only status[,] resulting in over 12,000 MW of demand response-based capacity resources having very similar operational characteristics. PJM has experienced a… marked difference in operational comparability between generation and demand response given the notice requirements and emergency-only status of most of the demand response resources. These significant differences… limits [*sic*] the usefulness of today's demand response resources to PJM operators in preventing the triggering of emergency conditions and then responding to emergency conditions once they have materialized. Unfortunately, to date, those demand response resources do not offer more diverse operational characteristics even though they are physically capable of doing so. PJM believes demand response resources can be available in a manner largely comparable to generation and that market rules should be adapted to provide the necessary incentives.[78]

FERC has recently approved PJM's request to place a cap on the quantity of capacity procured from demand response that has limited availability.[79] PJM requested the procurement cap because it believes that substituting limited-availability demand response for higher-availability resources has suppressed auction clearing prices and has impeded its ability to procure capacity to ensure grid reliability.

The plain implications are that the security value of demand-side resources can be less than that of supply-side resources, and that more costly incentives may be required to get performance from demand-side resources than are needed to get similar performance from supply-side resources.

Furthermore, there is some question about the durability of demand-side resources. For example, some entities that offered demand-side resources in ISO New England's initial capacity auction did not continue to offer part of that capacity in subsequent auctions. Instead, they ultimately purchased supply-side capacity to cover about a quarter of their capacity

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[78] *Statement Of Andrew Ott, Executive Vice President – Markets, PJM Interconnection, L.L.C.*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, before the Federal Energy Regulatory Commission, Docket No. AD13-7-000, September 9, 2013.

[79] FERC, 146 FERC ¶ 61,052, *Order on Proposed Tariff Changes*, Docket No. ER14-504-000, January 30, 2014.

commitments for the 2013/14 Commitment Period. If demand-side resources do not possess longevity comparable to that of supply-side resources, they are not as reliable or as valuable as supply-side resources.

5.3.5. Summary

Table 3 and Table 4 show the fuel mixes of each of the regions in 2011. The tables show that coal is still king in the nation's coal-rich old industrial regions (MRO, RFC, MISO, and PJM), while natural gas is the technology of choice elsewhere in the country. The second and third ranking fuel choices vary regionally and across the RTOs based on the advantages afforded a particular fuel and technology by virtue of geographic endowments or proximity to fuel sources. For example, hydro places second in CAISO and WECC (which have substantial and ubiquitous elevation drops), and wind ranks third in MRO and ERCOT (which have the best conditions for wind production). Nuclear continues to have a strong presence in three reliability regions – NPCC, RFC, and SERC, which include ISO NE, MISO, New York ISO, and PJM. Petroleum has a significant market share only in the old industrial states of the northeast (NPCC, including ISO NE and New York ISO). Solar has yet to make any significant gains in any region of the country but Florida.

Figure 12 and Figure 13 summarize net summer generation capacity in 2000 and 2012 by fuel types for the non-RTO regions compared to the RTOs. The figures show the change over the past decade in the degree of penetration of renewables (solar thermal and PV and wind), as well as shifts (generally reductions) in reliance on more traditional fuels such as coal and natural gas. The wind output in the central and west central regions of the country (served by ERCOT, MISO, SPP, and non-RTO states) is part of what is driving the significant expansion of the transmission grid that will enable that output to be transported to the eastern load pockets.

Table 3
Fuel Mixes of the Regional Reliability Organization Regions, 2012[80]

Fuel Type	FRCC	MRO	NPCC	RFC	SERC	WECC
Coal	17.1%	41.6%	7.0%	46.2%	33.5%	16.0%
Hydro	0.1%	4.5%	12.6%	3.1%	8.2%	26.7%
Natural or Other Gas	57.3%	24.3%	44.0%	30.0%	38.4%	40.1%
Nuclear	7.1%	7.6%	13.2%	11.6%	15.0%	4.6%
Petroleum	15.2%	4.4%	17.5%	4.6%	1.9%	0.4%
Solar	0.1%	0.0%	0.1%	0.2%	0.1%	1.2%
Wind	0.0%	16.4%	3.2%	2.6%	1.2%	8.8%
Other	3.2%	1.1%	2.2%	1.6%	1.8%	2.3%

[80] Derived from U.S. Energy Information Administration, Form EIA-860 for 2012 Final, Release Date October 10, 2013, obtained at http://www.eia.gov/electricity/data/eia860/. Texas Reliability Entity and Southwest Power Pool Regional Entity are not presented because of the significant intersection with ERCOT and SWPP as RTOs presented in Table 4.

Table 4
Fuel Mixes of the RTO Regions, 2012[81]

Fuel Type	CA ISO	ERCOT	ISO NE	MISO	NY ISO	PJM	SPP
Coal	0.5%	21.1%	7.2%	45.2%	6.8%	40.7%	31.6%
Hydro	19.6%	0.6%	10.5%	4.4%	14.5%	5.1%	3.2%
Natural or Other Gas	58.8%	61.3%	40.4%	28.0%	47.2%	29.9%	49.5%
Nuclear	6.2%	4.5%	13.2%	10.6%	13.3%	13.8%	6.6%
Petroleum	0.3%	0.5%	19.0%	2.5%	10.7%	6.4%	2.4%
Solar	1.6%	0.1%	0.1%	0.0%	0.1%	0.2%	0.1%
Wind	7.7%	11.1%	2.2%	8.5%	4.1%	1.6%	5.6%
Other	5.2%	0.8%	7.3%	0.7%	3.2%	2.3%	0.9%

For non-RTO regions of the country, coal capacity has not changed over the past decade; but its share has declined significantly and is now second in importance to gas-fired capacity. Solar technology has not entered the fuel mix in non-RTO regions, but wind has now a small but significant presence.

[81] Derived from U.S. Energy Information Administration, Form EIA-860 for 2012 Final, Release Date October 10, 2013, obtained at http://www.eia.gov/electricity/data/eia860/ .

Figure 12
Net Summer Generating Capacity (MW) by Non-RTO and RTO Regions, 2000[82]

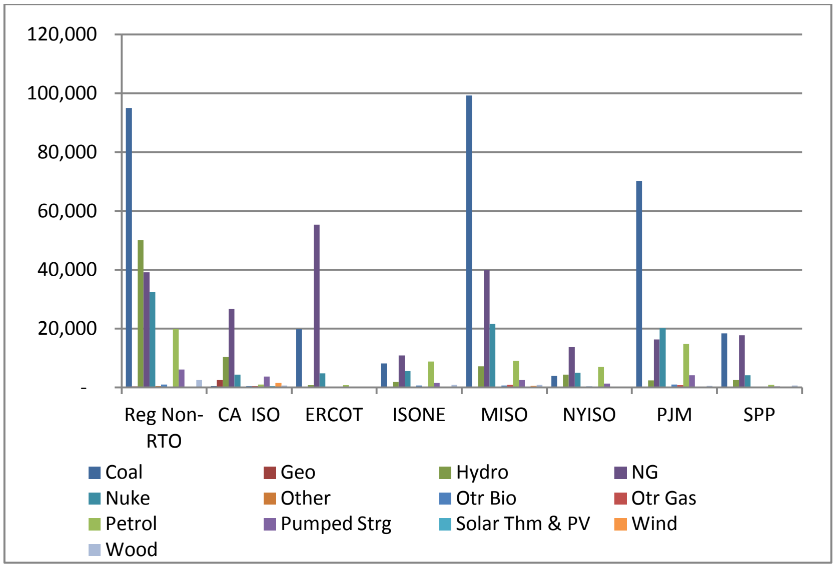
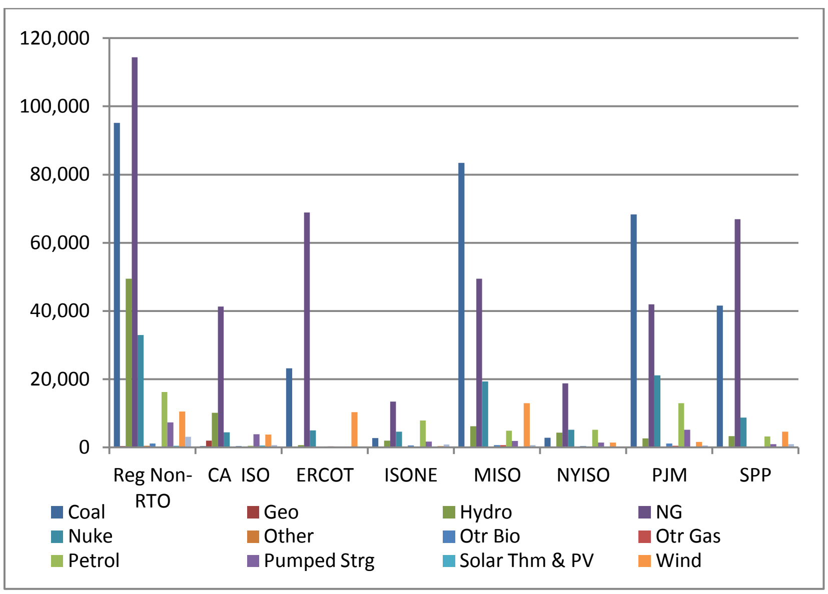


Figure 13
Net Summer Generating Capacity (MW) by Non-RTO and RTO Regions, 2012[83]



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[82] Energy Information Administration, *Existing capacity by energy source, by producer, by state back to 2000* obtained at http://www.eia.gov/electricity/data.cfm, Original source: Form EIA-860, Annual Electric Generator Report, 2000.

[83] Derived from U.S. Energy Information Administration, Form EIA-860 for 2012 Final, Release Date October 10, 2013, obtained at http://www.eia.gov/electricity/data/eia860/.

In nearly every RTO region, gas-fired generation capacity has at least doubled over the past decade. The effect of a combination of state renewable portfolio standards and geographical advantages have allowed wind capacity to increase from almost nothing in 2000 to relative significance in 2011 in all RTO regions outside of the northeast.

5.4. Net Revenue Analysis

To assess the market incentives for capacity investments, several RTOs estimate the profits that would have been earned in their markets by certain generation technologies. Specifically, the RTOs' analyses quantify each technology's net revenues – that is, the amount by which a generator's revenues from the sale of energy and ancillary services can be expected to exceed its variable production costs. This excess is available to cover a generator's fixed costs (including return on investment). If this excess covers only a part of a generator's fixed costs, the generator will lose money unless the shortfall can be covered by the generator's capacity market revenues.

In principle, it is economic for net revenues to be deficient persistently when the market has surplus capacity because, in such a situation, the price mechanism should not signal a need for additional capacity. It is also economic for net revenues to be excessive persistently when the market is short on capacity because, in such a situation, the price mechanism *should* signal a need for additional capacity. Net revenue analysis may yield findings that temporarily contradict these principles due to temporary fluctuations in market or economic conditions, such as may occur because of weather or unusually high or low forced outages of resources. If net revenue analysis yields findings that persistently contradict these principles, there is a market design problem.

Table 5 and Table 6 summarize the estimated net revenue for new combustion turbines and combined cycle units in RTOs for each of the years 2005 through 2012. The figures in these tables, which were developed by the RTOs or their independent market monitors, represent the revenues that would have been earned in the energy and ancillary services markets (and in capacity markets, where those exist) by a hypothetical combustion turbine or combined cycle unit operating in each year. The rightmost column presents the PJM Independent Market Monitor's estimate of capacity costs levelized (in nominal dollars) over twenty years.[84] For both natural gas plant types, net revenues on an RTO-wide basis were generally insufficient to cover levelized costs, with the exception of New York in 2005-2007 for combined cycle plants. The summer peak reserve margins shown in Figure 7 imply some need for new resource capacity during the boom years of 2005-2007; so this insufficiency implies a failure to signal shortages in these years.

[84] For simplicity, we used PJM's estimates of CONE as bases for comparison even though the other RTOs estimate CONE for their respective markets. The estimates vary among RTOs for a variety of reasons. Use of the other RTOs' CONE estimates would lead to similar general conclusions about the insufficiency of revenues to support entry.

Table 5
Comparison of Net Revenue for Combustion Turbine Gas Plant ($ per MW-month)[85]

Year	CAISO	ERCOT	ISO NE	MISO	NYISO	PJM	Levelized Cost
2005					1,917	833	6,000
2006					3,167	1,250	6,667
2007	4,333	3,333			4,167	4,083	7,583
2008	5,083	7,583			5,667	4,250	10,333
2009	4,917	3,667			5,250	4,833	10,750
2010	4,417	3,750	2,500	2,250	3,833	7,667	10,917
2011	3,750	9,167	2,333	2,250	3,333	7,167	9,250
2012	4,083	2,083	2,000	2,333	1,750	4,500	9,417

Table 6
Comparison of Net Revenue for Combined Cycle Gas Plant ($ per MW-month)[86]

Year	CAISO	ERCOT	ISO NE	MISO	NYISO	PJM	Levelized Cost
2005					10,250	3,417	7,833
2006					10,417	4,167	8,250
2007	7,500	7,083			13,333	8,417	12,000
2008	10,000	12,500			10,833	8,667	14,250
2009	3,250	5,000			5,000	8,667	14,417
2010	2,750	6,250	3,333	3,167	6,833	12,333	14,583
2011	1,917	11,667	3,167	3,000	5,167	13,000	12,833
2012	2,750	3,333	2,917	3,333	7,667	10,833	12,917

[85] The RTOs assume that combustion turbine units have heat rates between 10,250 and 10,500 MMBtu per MWh. See California ISO, *2011 Annual Report on Market Issues & Performance*, Department of Market Monitoring, April 2012; California ISO, *2012 Annual Report on Market Issues & Performance*, Department of Market Monitoring, April 2013; Potomac Economics Ltd., *2012 State of the Market Report for the ERCOT Wholesale Electricity Market*, June 2013, Figures 63 and 64, pp. 76 & 77; The Brattle Group, *2013 Offer Review Trigger Price Study*, October 2013; Potomac Economics, *2012 State of the Market Report*, for MISO, Figure 6, p. 10; Potomac Economics, *New York ISO 2008 State of the Market Report*, Figures 10 and 11, pp. 36-37; Potomac Economics, *New York ISO 2012 State of the Market Report*, Figures A-14 and A-15, p. A-22; and Monitoring Analytics, 2008 and 2012 *State of the Market Report for PJM*, Net Revenue Analysis sections. The New York figures are averages of values for the Hudson Valley and Capital Zones for 2004-2007, and averages for the Hudson Valley, Capital, and West Zones for 2008-2012. 20-year levelized cost figures are from Monitoring Analytics, 2008 and 2012 *State of the Market Report for PJM*, obtained at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012.shtml.

[86] The RTOs assume that combined cycle units have heat rates between 7,000 and 7,500 MMBtu per MWh. Sources are the same as listed in the preceding footnote.

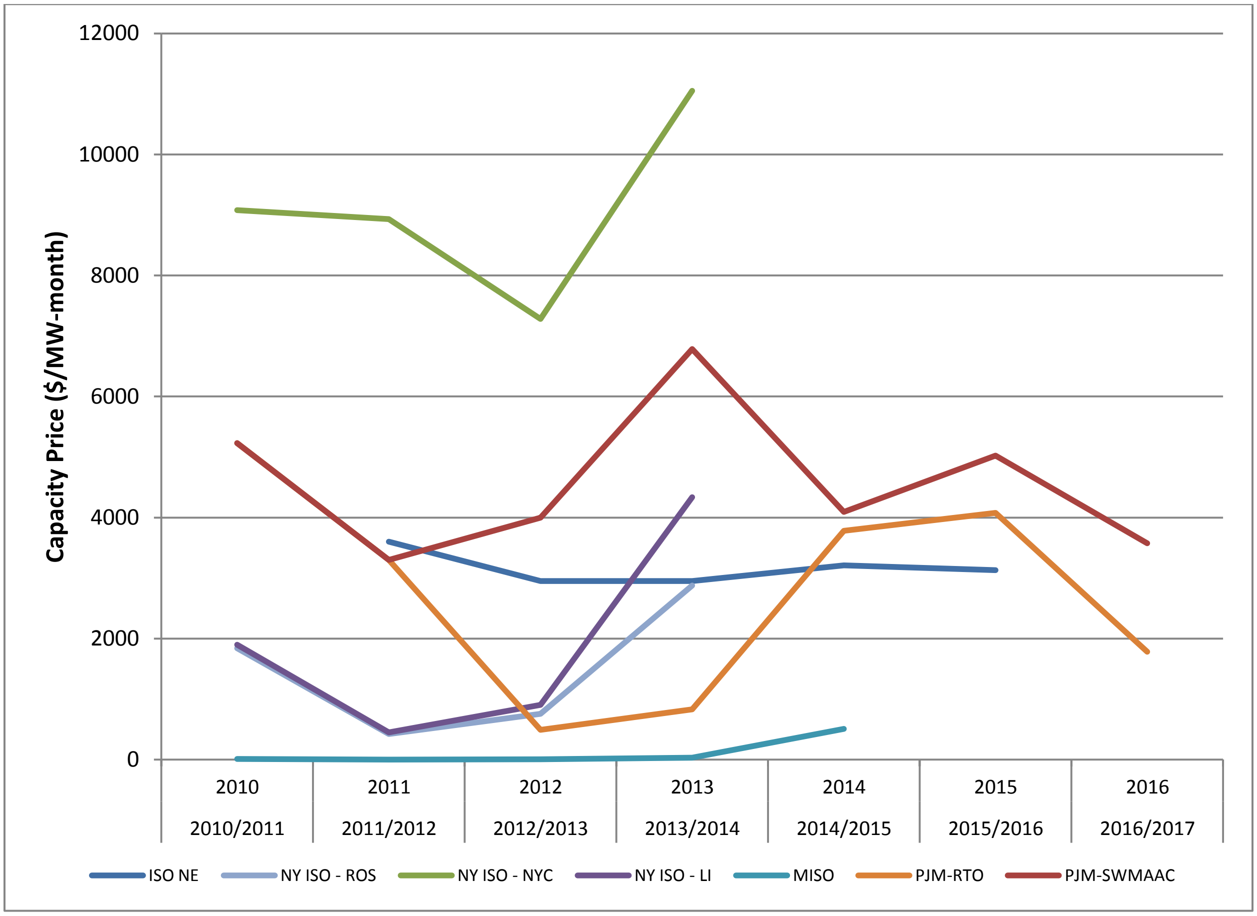
Although the net revenues presented in Table 5 and Table 6 represent overall regional averages, net revenues actually vary by zones within each RTO. Hence, in some RTOs, there are some zones, particularly in metropolitan and industrial regions with relatively high loads, in which net revenues have been high enough to cover levelized costs.[87] Furthermore, investors' expectations of a plant's profitability are shaped by many factors and may not depend on achieving an annual return on levelized cost over the plant's long life. Consequently, the information in these tables should be interpreted to mean that the RTOs' market prices have generally not been sufficient to cover levelized costs.

5.5. Price Trends

Capacity market prices have been volatile over the past decade and have remained volatile even as some of those RTOs – ISO NE, PJM, and New York ISO – launched centralized forward capacity markets in the mid-2000s. Figure 14 summarizes the capacity market prices for selected zones of the Eastern RTOs over delivery years 2010-2016. The selected zones – New York City and Long Island zones for the New York ISO and Southwest Mid-Atlantic Area Council for PJM – are included to illustrate the price separation among capacity markets that can occur when transmission constrains deliverability of capacity among zones. Both MISO and New York ISO's prices are set for a delivery year only one year ahead, while ISO New England and PJM conduct auctions that set capacity prices for a delivery year from three to five years in the future.

[87] For example, in PJM in 2013, a new combined cycle plant would have earned sufficient revenues from the energy, ancillary services, and capacity markets to cover levelized costs in seven if PJM's twenty zones. Nonetheless, a new combustion turbine would not have earned sufficient revenues in 2013 to cover levelized costs in any of the twenty zones.

Figure 14
Capacity Market Prices: RTO-Wide and Selected Zones ($/MW-month)[88]



5.6. Cost Trends

Figure 15 summarizes the levelized cost of energy for selected renewable and conventional generating technologies over the period 2008 to 2013. Costs for 2008-2011 are reduced by various tax subsidies, while costs for 2012-2013 do not consider such subsidies.

The figure shows that gas combustion turbines have the highest levelized costs, of over $200 per MWh, which occurs because they are used for peaking purposes in relatively few hours of each year. Solar thermal technologies have the second highest costs, of about $150 per MWh, while solar photovoltaic (PV) technologies had the third highest costs until their costs

[88] New York ISO prices include Rest of State (ROS), New York City (NYC), and Long Island (LI). PJM prices include RTO and SW Mid-Atlantic Area Council. The horizontal axis displays calendar years (on top) and delivery years (on bottom). Prices for New York ISO and MISO correspond to averages based on calendar year, while prices for ISO NE and PJM are based on a twelve-month delivery year that straddles two calendar years.

significantly dropped in 2013 with improvements in utility-scale technologies. In favorable locations, utility-scale solar technologies are now competitive on a levelized cost basis with IGCC, nuclear, and coal plants, all of which have costs in the neighborhood of $100 per MWh. The least costly technologies, at around $75 per MWh, are gas combined cycle plants and wind turbines.

Note that the solar and wind costs, in addition to benefiting from targeted subsidies, do not include the costs of the backup generation and other services necessary to handle intermittency. Solar and wind capacity may not be available when they are needed most. In addition, levelized costs of intermittent resources and those of conventional technologies, such as combustion turbines, are not comparable unless they are adjusted according to equivalent availability factors.

Figure 15
Levelized Cost of Generation Technologies, 2008-2013 (2011 $/MWh)[89]

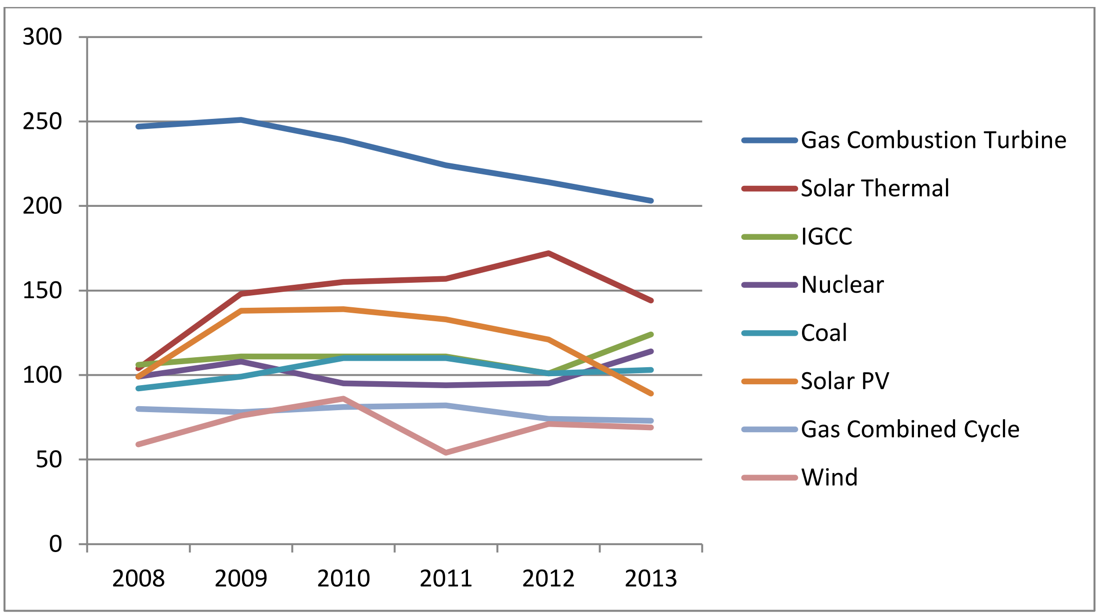


Figure 16 shows the capital costs per MW of capacity of selected renewable and conventional generating technologies over the period 2008 to 2013. Nuclear plants are the most expensive,

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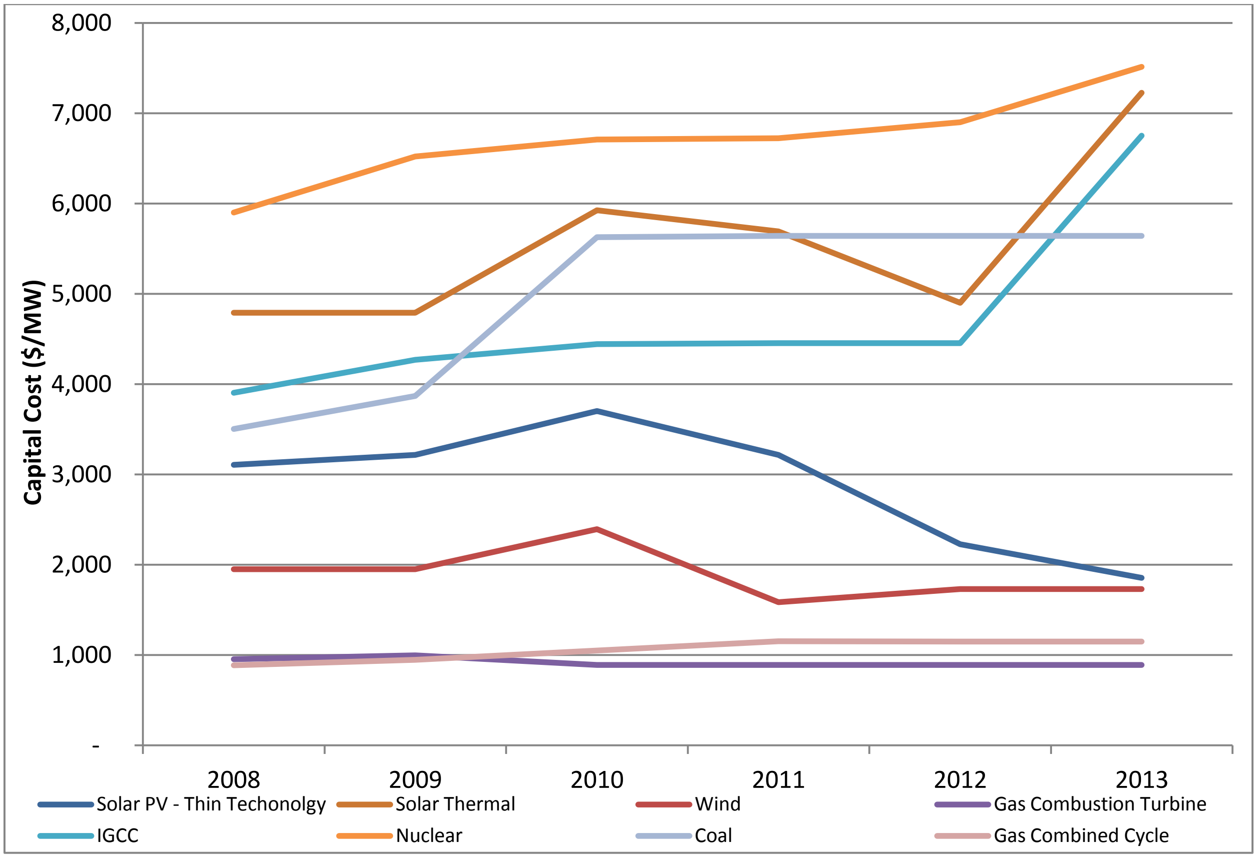
[89] Lazard Ltd., *Levelized Cost of Energy Analysis*, Version 2 (June 2008) through Version 7 (June 2013), Table Levelized Cost of Energy Comparison. For years 2008 through 2011, reported costs account for subsidies: Production Tax Credit, investment tax credit, and accelerated depreciation where applicable. Costs for 2012 and 2013 are expressed without subsidies. Costs assume a 20- to 40- year economic life, 40% tax rate, and 5- to 40-year tax life. For alternative technologies, the assumed capital structure is 30% debt at 8% interest, 50% tax equity at an 8.5% annual return, and 20% common equity at a 12% annual return. The capital structure for traditional technologies is assumed 60% debt at 8% interest and, 40% equity at a 12% return. Coal and gas prices vary by year. All costs are expressed in 2011 dollars.

rising from $5,900 up to $7,500 per MW during the period. IGCC, coal, and solar thermal plants have an intermediate level of expense, beginning around $3,500 per MW in 2008 and rising in 2013 to $4,300 in the case of solar thermal and to $6,800 in the case of IGCC. The cost of utility-scale solar PV fell from $3,100 to $1,900 while the cost of wind varied around $2,000 per MW. Gas combined cycle and gas combustion turbine plants are the least expensive plants, with costs around $1,000 per MW.

The levelized cost for each technology is determined based on an assumption about the technology's capacity factor, which generally corresponds to the high end of its likely utilization range. For example, the Energy Information Administration (EIA) assumes a 30% percent capacity factor for simple combustion turbines (conventional or advanced technology) that are typically used for peak load duty cycles. In contrast, the duty cycle for intermittent renewable resources such as wind and solar is dependent on the weather or solar cycle and so will not necessarily correspond to operator-dispatched duty cycles. Consequently, levelized costs of intermittent resources are not directly comparable to those for other technologies (even when the average annual capacity factor may be similar) and therefore direct comparisons made on the basis of Figure 15 should be made with extreme caution.

Figure 16
Capital Costs of Generation Technologies, 2008-2013 (2011 $/MW)[90]



Given their relatively low capital and operating costs, it is apparent why gas combined cycle plants are the technology of choice. The other technologies are attractive for their low costs under special conditions (e.g., solar in sunny climates, gas combustion turbines for peaking purposes), for their environmental benefits (e.g., wind), or for fuel diversity.

5.7. Observations

The centralized capacity markets were created to provide resource owners with steady income streams, thereby helping encourage generation investment and delays in generation retirements. Thus far, however, the centralized capacity markets have provided rather volatile income streams, as is evident from the price histories shown in Figure 14; and reasonable questions may be raised about how generators with thirty- to fifty-year lives can gain financial solace from capacity markets that look only a few years into the future.

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[90] *Id.*

Further investment uncertainties arise from the fact that capacity is not a real product: consumers want the energy that capacity provides; and system operators want the operating reserves and other ancillary services that capacity provides; but nobody wants capacity for the mere pleasure of having steel in the ground. In traditional markets, capacity has implicitly been a call option that gives the capacity purchaser the right to obtain electrical energy from the capacity seller under particular circumstances. In the centralized markets, by contrast, “capacity” is a product that gives no right to the purchaser except to meet whatever capacity obligation is determined by the RTO.

Having little anchor in physics or economics, both the definition of “capacity” and the constructions of capacity market demand curves have been and will continue to be subject to perpetual controversy. When RTOs suddenly change their minds about the extent to which demand-side resources can count as capacity, or the extent to which intermittent wind resources can count as capacity, or whether certain capacity will be subject to minimum offer pricing restrictions, or when congestion will change the definitions of capacity pricing zones, capacity prices can change substantially.[91] The different ways that RTOs set the capacity demand curves likewise have large impacts on capacity prices. Because definitions of “capacity” and capacity demand curves are artificial, they will change over time and thereby have a limited ability to offer steady income streams.

5.7.1. Relationships of Market Design to Resource Adequacy

Figure 17 and Figure 18 present forecast summer reserve margins for traditionally regulated and RTO regions, respectively. For each region, the bars indicate NERC forecasts of anticipated planning reserve margins for 2014, 2018, and 2023; and the black horizontal lines indicate required reserve margins (i.e., NERC “Reference Reserve Margin Levels”).

The figures show that planning reserve margins are projected to decline significantly across much of the country between 2014 and 2023, with the largest percentage declines in MISO, ERCOT, SERC-E, NPCC-NE, SERC-W, MRO-MAPP, and SERC-N. These declines reflect the expectation that large quantities of coal-fired capacity will be retired as a result of increasingly more stringent and costly environmental compliance rules. MISO and ERCOT appear to be most affected, with projected planning reserve margins falling below 5%, while SERC-E is a close third with projected reserve margins below 10%. There appears to be no section of the country

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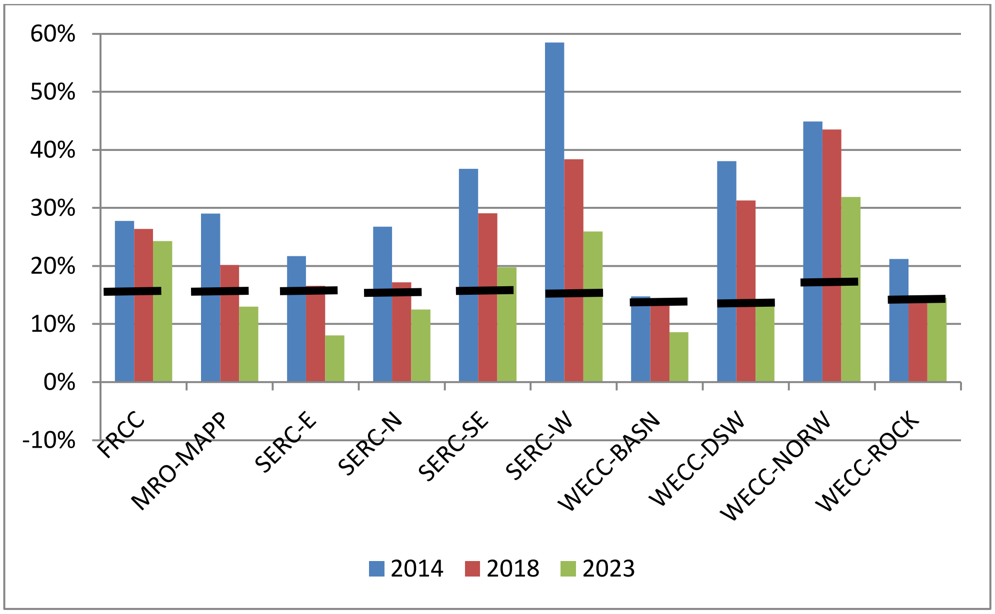
[91] For example, PJM eliminated the Interruptible Load for Reliability (ILR) demand-side product effective for the 2012/2013 Delivery Year. ILR resources were not eligible to offer capacity in PJM’s capacity market because, instead of providing the three-year advance commitment required for capacity resources, ILR allowed certification in as little as three months prior to the delivery year. For demand response resources procured under the ILR program to continue to serve as capacity resources after the program’s elimination, they had to comply with the rules governing PJM’s capacity market. To compensate for the elimination of short-term demand-response resources due to the discontinuance of ILR, short-term demand-side resources were accommodated by removing 2.5% of the reliability requirement from the demand curve in the BRA for auctions close to the actual delivery year. The movement of significant demand-side capacity into the BRA coupled with the reliability requirement reduction led to significant drop in the market prices for capacity in the 2012/2013 BRA and subsequent years.

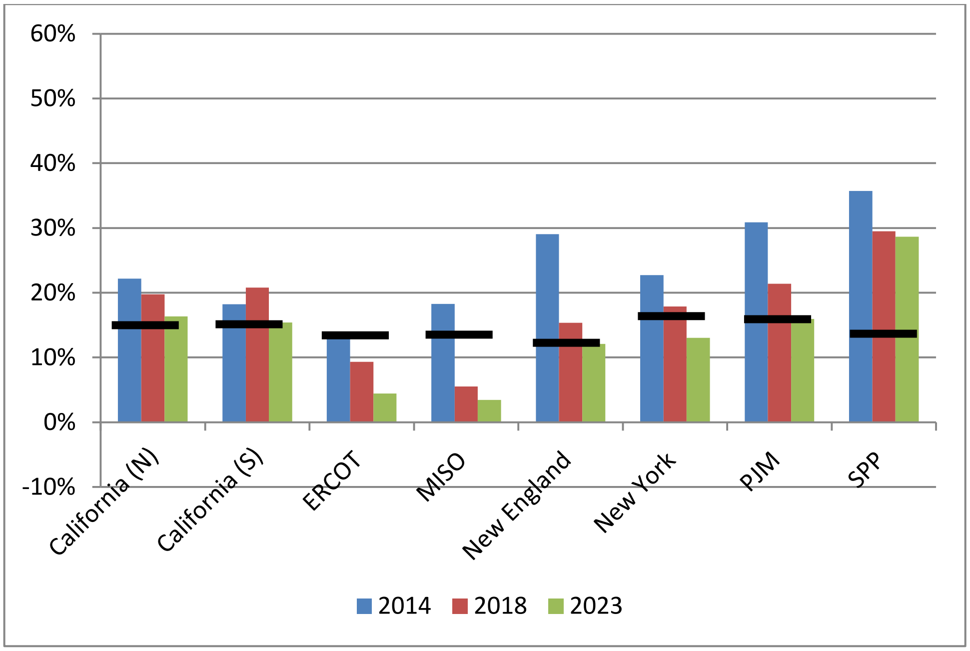
that escapes the impact of retirements and the increasing role played by renewable technologies under state RPS mandates.

Figure 17
Forecast Summer Reserve Margins for Traditionally Regulated Regions[92]



[92] North American Electric Reliability Corporation, *2013 Long-Term Reliability Assessment*, December 2013, pp. 15-17.

Figure 18
Forecast Summer Reserve Margins for RTO Regions[93]



The most striking difference between the traditional and RTO regions is that the traditional regions have higher forecast reserve margins than the RTO regions in all forecast years. The respective simple averages for the three years 2014, 2018, and 2023 are: traditional regions, 31.9%, 25.2%, and 17.2%; RTO regions, 23.8%, 17.4%, and 13.7%. A plausible explanation for this result is that the relatively stable regulated returns on investment in traditionally regulated regions tends to induce ample resource investment in these regions, while competition in the RTO regions tends to induce cost-cutting that drives reserve margins to be closer to requirements.

Consistent with this difference in forecast reserve margins and with the similarity in reserve requirements among regions, none of the traditionally regulated regions are forecast to violate reserve requirements in 2014 or 2018, while ERCOT is forecast to violate requirements in both years and MISO is forecast to violate requirements in 2018. Half the traditionally regulated regions and half the RTO regions are forecast to violate requirements in 2023; but because of the conservative assumptions underlying the forecasts, most of these violations are unlikely to occur as there is still ample time to take remedial action. For example, IRP processes in traditionally regulated markets typically project reserves as though no previously uncommitted resource additions will be made even though these IRP processes typically require building or procuring wholesale capacity well in advance of the capacity need.

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93 *Id*.

Capacity market design seems to have a modest impact on reserves. A statistical test of the difference between the average reserve margins for traditional and RTO markets finds that these markets differ at the 10% level of significance, with the RTO market average lower than the traditional market average. There is thus some statistical evidence that RTO markets tend to have lower reserve margins than traditional regulated markets, but this does not explain the significant difference between the forecast reserve margins of the two market groups.

5.7.2. Assessment of Resource Diversity Effects

The shift away from coal-fired generation to natural gas and renewables may create problems for grid stability and reliability. The intermittency of wind and solar generation will have to be backed by a reasonable combination of baseload, intermediate, and peaking generation – and possibly storage, if it becomes cost-effective in the future – with fast start, load following and ramping characteristics. Public policy that influences long-term generation planning must be guided by an appreciation of the benefits of fuel diversity for maintaining a reliable power supply.

This dramatic shift away from the use of coal has significant implications for the diversity of the U.S. electricity generation portfolio, for electricity suppliers, and for their customers. As the U.S. incorporates greater amounts of intermittent renewable resources into the nation's generation mix, the need to maintain diversity in the baseload power portfolio is critical.

5.7.3. Long-Term Contracting and Generation Investment

Long-term bilateral power purchase contracts are crucial to the functioning of electricity markets. They give price stability and certainty to both buyers and sellers, thereby helping manage risk and thereby supporting new resource development. Prudent business practice would have utilities and LSEs procure most of their capacity resources through ownership or bilateral contracts, with short-term markets serving as the venue for rectifying inevitable mismatches between resources and obligation. Arbitrage should cause bilateral contract prices to reflect risk-adjusted expectations of short-term market prices.

In jurisdictions with traditional regulation of electric utilities, which includes states within RTO regions as well as those in non-RTO regions, just about all electricity is procured either through self-supply or through competitive wholesale market solicitations that result in bilateral arrangements. In restructured regions, the short-term timeframe of the RTOs' centralized capacity markets seems far too short in duration (one to three years) to provide new capital-intensive capacity with the revenue guarantees necessary to support favorable financing. The eastern RTOs have tried to address this issue by instituting forward locational capacity markets that nonetheless fail to provide the long-term assurance of revenues which would be needed to adequately support generation investments.

5.7.4. Natural Gas Deliverability

Power systems increasingly rely on natural gas-fired capacity for a number of reasons, including low gas prices. This increase has exposed power systems and LSEs in much of the country to the risk that sufficient gas may not be available to meet power system needs during periods of very high seasonal demand, under other stressed system conditions, or when facing contingencies associated with natural gas supply/transportation system infrastructure. Gas deliverability constraints, rather than gas production constraints, are the concern.

Deliverability threatens the reliability of power systems due to the limited capacity of the pipelines used to transport gas, coupled with the "just-in-time" nature of the resource as used by power generators. The reliability risks partly arise from the differences between gas and electric system operational requirements and market mechanisms. Gas transportation systems are designed to meet the needs of firm (non-interruptible) contract holders (historically comprised mostly of Local Distribution Companies) that draw gas more slowly and predictably from pipelines than do generators. Uncertainties in generation availability, commitment, and dispatch make it risky for any one independent generator to choose long-term firm contracts for gas delivery. On the other hand, as non-firm gas delivery customers, gas-fired generators can be interrupted when pipelines are unable to fully meet gas demand, which leads to electric reliability issues. Utilities with fleets of gas-fired generators have the economy-of-scale advantage of being able to commit to firm (non-interruptible) gas transportation because they can depend upon the average availability, commitment, and dispatch of the fleet to be more stable than availability, commitment, and dispatch of any single generator.

The risks created by the power industry participants that rely on non-firm gas transportation were made apparent by the exceptionally cold "polar vortex" that gripped much of the Midwest in the winter of 2013/2014. The combination of record-high winter peak electricity loads, gas deliverability constraints, and volatile gas prices caused wholesale price spikes as generators and other gas consumers without firm gas transportation commitments struggled to procure natural gas. In anticipation of such conditions, FERC decided in November 2013 to allow interstate natural gas pipeline and electric system operators to share nonpublic operational information to facilitate natural gas and power reliability.[94]

The growing interdependence of the natural gas supply and bulk power supply system has focused attention of participants and policy makers in both the gas and electric industries on ways to improve natural gas-electricity interactions and coordination. Efforts in some regions of the country (the northeast in particular) and at the national level (at FERC and by NERC) have been made to analyze the problems and to consider fuel supply and transportation adequacy as a formal part of electric reliability assessments and short- and long-term planning.[95] On the electric side of the relationship, some changes to RTOs' energy, ancillary service and capacity

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[94] Federal Energy Regulatory Commission, Order No. 787, *Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators*, 145 FERC ¶61,134, 18 CFR Parts 38 and 284, Docket No. RM13-17-000, November 22, 2013.

[95] For example, see North American Electric Reliability Corporation, *2013 Special Reliability Assessment: Accommodating an Increased Dependence on Natural Gas for Electric Power: Phase II, A Vulnerability and Scenario Assessment for the North American Bulk Power System*, May 2013; and Federal Energy Regulatory Commission Staff, *Gas-Electric Coordination Quarterly Report to the Commission*, Docket No. AD12-12-000, September 19, 2013; and PJM, LLC, *Gas Electric Senior Task Force Problem Statement*, 2013.

market rules have already been made and others likely will have to be made to accommodate the challenges created by gas pipeline inadequacy for non-firm users and the "just-in-time" nature of gas acquisition for power production that can at certain times severely limit operating and planning reserve margins.

5.7.5. Plant Retirements

As shown in Figure 19, about 23,000 MW of coal-fired generating capacity retired between 2005 and 2013, and another 37,300 MW is expected to retire over the next decade, mostly during the next four years. The retirements are due to a combination of increasingly stringent environmental regulations, an aging coal fleet, more efficient new generating technologies, low gas prices, modest demand growth, and policies favoring renewable resources.

Figure 19
Actual and Projected Coal-Fired Capacity Retirements, 2005 to 2026[96]

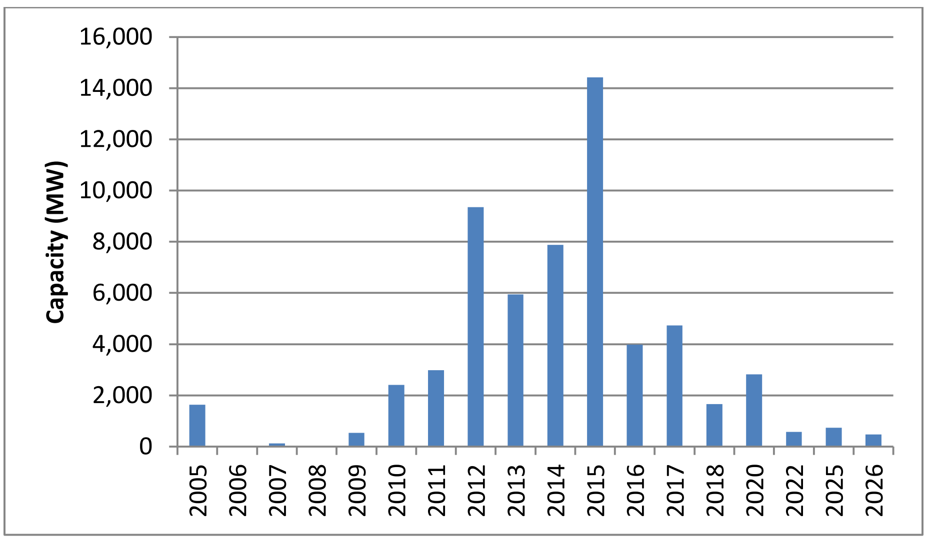
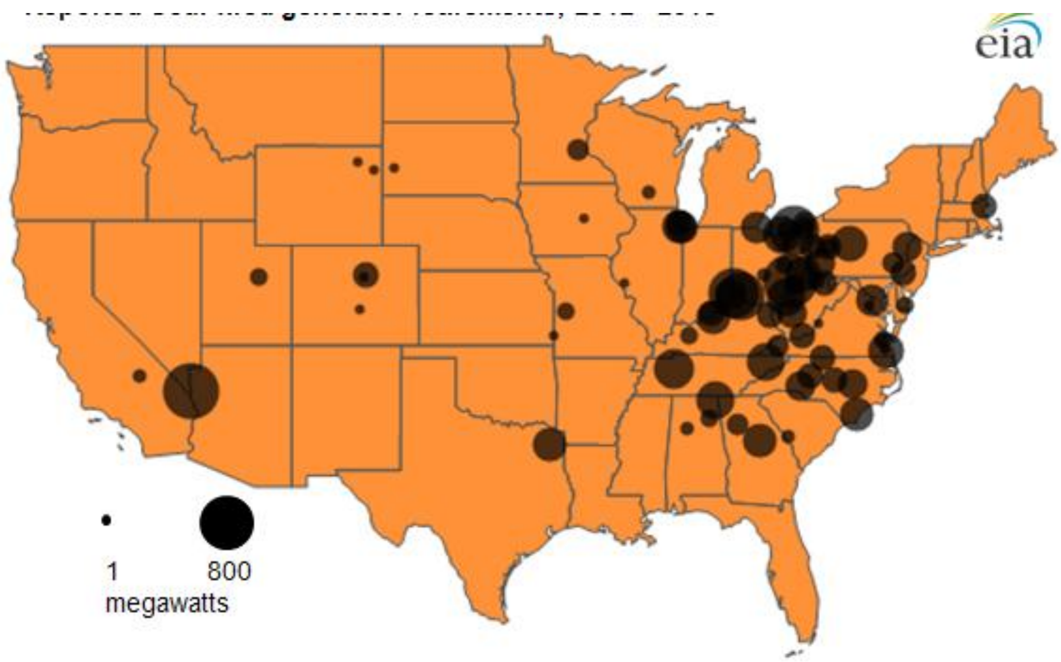


Figure 20 shows that coal-fired generation retirements are concentrated in the Midwest and mid-Atlantic states.

[96] SourceWatch, Table 2, http://www.sourcewatch.org/index.php/Coal_plant_retirements.

Figure 20
Reported Coal-fired Generator Retirements – 2012 to 2016[97]



5.7.6. Reliability Issues Arising from Intermittent Resources

Wind- and solar-powered resources provide power only when the wind blows or the sun shines. The resulting intermittency of their power output creates system control problems that are costly to resolve. As intermittent resources' share of total capacity increases, there must be other generation readily available to back up these resources when they do not provide power.

Making matters more difficult is the fact that subsidized wind and solar resources can depress energy prices. Consequently, at the same time that intermittent resources create a need for fossil fuel-fired generation to compensate for their intermittency, they reduce the energy revenues that fossil fuel-fired generation can hope to receive.

The recent and ongoing experience in Germany provides some lessons about the impacts of and unintended consequences of relatively rapid adoption of high penetration levels of wind and solar resources. As should be expected, the significant market shares of wind and solar resources in Germany has driven down German wholesale market prices substantially and created problems in maintaining grid reliability in the face of large swings in intermittent power output, leading Germany's power system operators to curtail renewable energy production 21% of all hours (1,800 hours) in 2011 and 82% of all hours (7,200 hours) in 2012.[98] The

[97] http://www.eia.gov/todayinenergy/detail.cfm?id=7290

[98] "Germany's Retail Tariffs Now Decoupled from Wholesale Rates, "*The Electricity Journal*, November 2013, 26(9): 7-8. Also see Bundesnetzagentur, *Report on the State of the Grid-based Energy Supply in Winter 2011/2012*, May 3, 2012.

depressed German energy market prices have put resource adequacy at risk because some dispatchable resources, such as natural gas fired turbines, are less economically viable.

6. PROSPECTIVE RELIABILITY IMPACTS OF EVOLVING TECHNOLOGY

Advances in power system technologies will have three general sorts of impacts on power system security and reliability. First, they will increase actual or effective resource capacities. Second, they will improve the control capabilities of power system operators. Third, they will add to the complexities of controlling power systems.

6.1. Increases in Resource Capacities

As a general rule, technological improvements reduce the real (inflation-adjusted) costs of generation resources and improve the technical efficiencies (output per input) of those resources. Such improvements will therefore increase the supply of resources available at any given cost level.

Improvements in storage technologies – in terms of both costs and physical capabilities – will improve the competitiveness of intermittent generation technologies. Whether these improvements will be sufficient to make these technologies competitive (without subsidies) with conventional technologies is not yet knowable.

Improvements in transmission technologies – such as those that increase the carrying capacities of lines or reduce the costs of transmission equipment – reduce the costs of delivering power from resources to consumers. Such improvements will increase power systems' effective resource capacity.

6.2. Improvements in Power System Control

Power systems have already derived significant efficiency benefits from the development of regional joint commitment and dispatch of resources and the computerization of this commitment and dispatch. These benefits have come in two major forms: substitution of cheaper resources for more expensive resources; and reduced reserve requirements. Further improvements in computer technologies and further regionalization of power system control promise additional benefits.

So-called "smart grid" technologies promise to allow extension of efficient commitment and dispatch to micro-resources, particularly demand resources and certain distributed generation resources. The effect of such an extension would be to increase the resource capacity that is available to the power system

6.3. Complications to Power System Control

Increasing penetration of intermittent generation resources has created and will create significant security and reliability challenges. The fundamental problem is that electricity supply and demand must be in balance at every moment in time, but the electric power fueled by the wind and the sun changes erratically and unpredictably from moment to moment. Until electrical energy storage becomes sufficiently cheap, power system operators will need to protect the security of power systems through various costly mechanisms for compensating for the intermittency of wind and solar resources. These mechanisms are dispatchable resources with high ramping rates that can, on very short notice, provide the capacity that intermittent resources cannot provide.

7. DIRECTIONS FOR FUTURE REFORM OF METHODS FOR ASSURING ADEQUATE CAPACITY

There are two basic sets of issues in assuring capacity adequacy. The first concerns defining the capacity mandate:

- How much capacity is needed?
- What qualifies as capacity?
- What types of capacity should be built?

The second set of issues concerns how to best meet the mandate:

- Who should be responsible for meeting the mandate?
- How can markets most efficiently be organized to meet the mandate?

Reform proposals address various aspects of the foregoing questions. This section begins with proposals to reform the capacity mandate, and then looks at proposals to reform the means of meeting the mandate.

7.1. Reforms in Defining the Capacity Mandate

7.1.1. Reformed Pricing of Operating Reserves

William Hogan of Harvard University has for many years promoted the idea of allowing operating reserve prices to signal real-time capacity shortages.[99] The basic notion is to reward resources' actual performance; but Hogan would partially displace capacity markets with enhanced operating reserve markets. Operating reserves do, after all, have the primary purpose of ensuring power system security. Hogan even claims that "There is a possibility that an operating reserve demand curve by itself would provide sufficient incentives to support resource adequacy without further developing forward capacity markets."[100]

Key elements of Hogan's approach include the following:

- Operating reserve curves would be downward-sloping, indicating that the marginal value of operating reserves falls as the quantity of operating reserves increases.

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[99] For a recent statement of his position on this issue, see W.W. Hogan, "Electricity Scarcity Pricing Through Operating Reserves," *Economics of Energy & Environmental Policy* 2(2): 65-86, IAEE, September 2013.

[100] *Id.*, p. 72.

- Operating reserve curves would be based upon the value of lost load and the probability of load curtailment. When there is involuntary load curtailment, the price of operating reserves would equal the value of lost load minus energy rents. When there is not involuntary load curtailment, the price of operating reserves would equal the value of lost load times the probability of load curtailment, minus energy rents.
- Operating reserve curves would be administratively determined, such as by the system operator.

Hogan's approach gives efficient real-time price signals, setting operating reserve prices at very high levels when power system security is at risk. These efficient price signals are not limited to operating reserves, however. Because many resources can offer both energy and reserves, arbitrage will cause energy prices to become very high when operating reserve prices become very high. The very high prices for operating reserves and energy would reward resources for being available when they are needed most and would send price signals consistent with the need for voluntary load reductions.

MISO has implemented a version of Hogan's approach that has a downward-sloping operating reserve curve, with a price based upon the value of lost load when reserves are near zero, and with a price that falls according to estimates of how the probability of load curtailment falls as reserves rise to the level of the reserve requirement. The operating reserve price does not depend upon energy rents as Hogan proposes, however, but is instead depends upon other factors, including the per-MWh average cost of committing and running a peaking unit for an hour.[101]

Hogan provides a theoretically correct approach to the problem of pricing operating reserves; but this approach will not solve the capacity adequacy problem because it will not provide sufficient revenues to cover capacity costs in systems with one-event-in-ten-year reliability standards. As Roy Shanker has noted:

> …while modifications to the energy market such as the operating reserve demand curve… would obviously improve real time energy price signals, they would not obviate the need for a capacity market. Indeed, the best solutions are where more efficient real time energy prices are combined with an appropriate capacity mechanism.[102]

Reformed pricing of operating reserves would improve the efficiency of day-ahead and real-time markets, and it might help recover some capacity costs that would not otherwise be recovered; but it would not provide sufficient capacity cost recovery.

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[101] MISO, *FERC Electric Tariff*, Schedule 28, "Demand Curves for Operating Reserve, Regulating and Spinning Reserve, and Regulating Reserve," November 19, 2013.

[102] *Comments of Roy J. Shanker Ph. D.*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, before the Federal Energy Regulatory Commission, Docket No. AD13-7-000, September 11, 2013, pp. 3-4.

7.1.2. Capacity Compensation Based on Actual Resource Availability

Power system security depends upon the resources that are *actually* available during peak periods rather than upon the resources that *promise* to be available. In particular, security is not enhanced by a generator that is out of service when reserve margins are tight, nor by demand-side resources that do not reduce load when needed. Consequently, capacity prices should reward actual availability both as a matter of efficiency (to encourage resources to be available when needed) and as a matter of fairness (so that consumers are paying only for capacity that has real value and not for capacity that does not perform).

Accordingly, Peter Cramton (of the University of Maryland) and Steven Stoft have proposed to reward only that "capacity that contributes to reliability as demonstrated by its performance during hours in which there is a shortage of operating reserves."[103] Key elements of their proposal include the following:

- Capacity prices should be based upon actual capacity rather than bid capacity. This prevents the withholding of capacity that would allow an exercise of market power.
- Capacity payments should be based upon the capacity price net of the *actual* energy rents rather than the *theoretical* energy rents of a benchmark peaking unit.[104] "Energy rents" are the energy and reserve profits of the benchmark peaking unit during the hours when there is an operating reserve shortage. Setting capacity payments in this manner would improve the price signal and would also limit the exercise of market power.

Joseph Bowring, the Independent Market Monitor for PJM, has concerns similar to those expressed by Cramton and Stoft. In particular, he has testified that PJM pays resources for their capacity even in cases "of complete nonperformance" and that PJM's "Wind, solar and hydro generation capacity resources are exempt from key performance incentives."[105] He further notes that PJM's resource performance measurements are faulty because they "do not correctly measure actual forced outage performance because they exclude some forced outages."[106]

Having a similar concern, PJM has requested that FERC allow it to change the rules governing its capacity market so that PJM can limit the amount of capacity outside the PJM territory that can

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[103] P. Cramton and S. Stoft, "A Capacity Market that Makes Sense," *Electricity Journal* 18: 43-54, August/September 2005.

[104] Cramton and Stoft acknowledge the difficulty of estimating the energy rents of an actual benchmark peaking unit in practical situations, such as when the unit has startup costs or a minimum start time that make a startup decision non-trivial.

[105] *Comments of the Independent Market Monitor for PJM*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, before the Federal Energy Regulatory Commission, Docket No. AD13-7-000, January 8, 2014, p. 5.

[106] *Id*., p. 6.

bid into its capacity auctions.[107] Oddly, PJM's forward auctions recognize locational constraints that limit the delivery of capacity *within* PJM, but not the locational constraints that limit the delivery of capacity to PJM from areas *outside* of PJM. Indeed, PJM does not recognize capacity import limits in its capacity auctions. With the tripling of capacity imports over the past six years and occasional curtailment of firm transmission service by neighboring power systems, this failure to recognize deliverability constraints attaches too high a value to the reliability benefits of capacity imports. This is yet another instance in which the real value of capacity is less than its nominal value.

ISO New England has recognized the fundamental principle of "pay for performance" in its recent proposal to FERC to amend its Forward Capacity Market (FCM) design. As ISO NE states:

> When sellers can depend on payment regardless of the quality of the product delivered, quality tends to suffer. When payments reward higher quality, quality tends to improve. While there have been many efforts to refine the FCM over the years, its design has always failed to reflect these most basic principles, and reliability in New England is deteriorating as a result.
>
> Much of the reason for the FCM's failure in this regard is its complexity. The product is poorly defined; while the region requires resources that reliably provide energy and reserves when supply is scarce, the FCM instead buys something only vaguely related to that, called "availability." The FCM applies different rules and different standards to different types of resources (even though it seeks to buy the same product from all of them), and includes numerous one-off provisions and exceptions. And at the end of the day, capacity "obligations" mean little because there are rarely financial consequences for failing to perform.
>
> Each of these elements of the current FCM is contrary to sound market design. This is not surprising, however, because the core FCM design was not based on any standard market model. Rather, the FCM was built from the ground up, without a blueprint, through a long series of negotiations and compromises. The result is an idiosyncratic design that is failing to meet its most basic objectives – ensuring reliability in a cost-effective manner. The solution to these problems is assuredly not more of the same. The FCM design must be fixed on a fundamental level.
>
> The Pay For Performance design presented here replaces the FCM's esoteric design with one that is familiar. Pay For Performance is a true, two-settlement forward market, following a blueprint that has been tested, refined, and applied successfully in myriad other markets, including New England's own energy markets. Pay For Performance is built around a well-defined product – the delivery of energy and reserves when they are needed most. Its rules are much

[107] PJM Interconnection, L.L.C., Docket No. ER14-503-000, November 29, 2013.

> more simple than the current FCM design, and those rules apply in the same manner to all resource types, without exceptions. With greater transparency and less uncertainty, Pay For Performance will create strong incentives for resource performance consistent with the goals of the capacity market.[108]

In summary, resources should be compensated for their capacity value only to the extent that they can support power system security when needed. Resource owners will have good incentives to perform only if they are paid for resources that are actually available when needed; and they should be penalized, or at the very least not paid, if their resources are not available when needed. This obvious reform should be undertaken expeditiously in all capacity markets that have a mismatch between rewards, penalties, and performance.

7.1.3. Recognition of the Diversity of Capacity Values

FERC has recently asked the power industry how capacity markets might better recognize the diverse values provided by different types of capacity resources. FERC specifically asked:

> Should existing capacity products be modified to reflect various operational characteristics needed to meet system needs? If there is a need for additional capacity products, how should those products be defined and procured in light of the current one day in ten year resource adequacy approach?[109]

Some parties have asserted that the capacity values of all resources should be recognized. For example, a coalition of thirty publicly owned electric utilities, cooperatively owned electric utilities, consumer advocates, state public utility commissions, investor-owned utilities, industrial customers, and independent power producers has urged FERC to recognize the diversity of values provided by different types of resources, the legitimacy of policies that favor some resources over other resources, and the legitimacy of resources procured under long-term contracts and self-supply.[110]

Parties representing some particular types of resources have declared that special consideration should be given to the ways in which their resources provide capacity. For example, EnerNOC, which is in the business of developing demand-response resources, seeks different capacity market standards for demand-side resources than for supply-side resources. The basis for these different standards is that demand-side resources and supply-side resources perform differently than one another and have different business models.

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[108] ISO New England, *ISO New England Inc. and New England Power Pool, Filings of Performance Incentives Market Rule Changes,* Docket No. ER14-1050-000, January 14, 2014, p. 2.

[109] Federal Energy Regulatory Commission, *Notice Allowing Post-Technical Conference Comments*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, Docket No. AD13-7-000, October 25, 2013, p. 3.

[110] AARP *et al*, *Letter to the Federal Energy Regulatory Commission*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, Docket No. AD13-7-000, February 10, 2014.

> Demand response resources… are not in the business of selling load reductions as a primary business… [M]ust-offer mechanisms may be a good fit for generation but are a poor fit for demand response. Generation will choose to be dispatched as often as it is profitable to provide energy, while demand response generally would prefer not to be interrupted.[111]

As another example, the Energy Storage Association seeks capacity market rules that enable storage to better participate in capacity markets:

> Integrating storage resources into the existing capacity markets by the development of rules specific to these resources, as has been done for other alternative resources such as demand response, will send the right market signals for investment.[112]
>
> Ensuring market rules are developed to enable storage resources to access to the capacity markets would remove a major barrier to investment in new storage resources.[113]
>
> …in any given hour, a storage resource can be withdrawing or injecting power and yet the capacity markets currently do not allow for this type of resource.[114]
>
> …energy storage facilities should be included in the planning process.[115]

The Maryland Public Service Commission advocates having separate capacity markets for existing resources and new resources:

> …RTO/ISOs could conduct bidding targeted at existing resources in the near to mid-term, while conducting a separate round of bidding designed and targeted at new resources that would be brought online in the mid to longer term; capacity that could come from upgrades at existing facilities or new generating resources. Surely, in almost every instance the payment necessary to persuade an existing efficient resource to commit to remaining available for a certain

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[111] *Comments of EnerNOC Inc. On behalf of Dan Curran, Principal, Market Strategy*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, before the Federal Energy Regulatory Commission, Docket No. AD13-7-000, September 10, 2013, p. 3.

[112] *Statement of the Electricity Storage Assocation [sic]*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, before the Federal Energy Regulatory Commission, Docket No. AD13-7-000, September 10, 2013, p. 3.

[113] *Id.*, p. 5.

[114] *Post-Technical Conference Comments Of The Energy Storage Assocation [sic]*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, before the Federal Energy Regulatory Commission, Docket No. AD13-7-000, January 8, 2014, p. 5.

[115] *Id.*, p. 6.

period into the future will be much less than that necessary to incent construction of a new power plant.[116]

The Maryland Public Service Commission also advocates capacity products of different durations:

> FERC should also look at the desirability of requiring capacity markets to establish capacity payment terms of greater than one year, perhaps using a portfolio of staggered contract terms such as three, five, or ten years for a defined percentage of capacity resources – this approach would minimize price volatility and provide long term price signals which would also provide greater revenue certainty to developers of new merchant generation.[117]

The Maryland Public Service Commission also advocates compensating capacity for its different operational characteristics:

> Capacity compensation should vary to reflect the type and value of the capacity services provided to the market. This includes providing quick start, shutdown and load-following capability…[118]

On the other side, the American Public Power Association opposes the development of multiple capacity products:

> Trying to adapt these [capacity] markets to accommodate specific resource types and attributes, while an admirable goal, would make them only more complex and difficult to administer, potentially leading to further unintended negative results and yet more band-aid market rule changes and exceptions to attempt to address these unintended results.[119]

Joseph Bowring and David Patton, the Independent Market Monitors for PJM and New York ISO, respectively, each say that the special operational attributes of certain resources, like quick response, are best rewarded by the energy and ancillary services markets rather than by capacity markets:

> …it does not make sense to subdivide the capacity market by operational characteristics or other attributes. Such character[ist]ics are best dealt with in the energy markets and the ancillary services markets. Subdividing the capacity market into multiple submarkets would add exponential complexity to an

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[116] *Comments of the Maryland Public Service Commission*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, before the Federal Energy Regulatory Commission, Docket No. AD13-7-000, September 9, 2013, p. 6.

[117] *Id.*

[118] *Id.*, p. 7.

[119] *Written Statement Of Susan N. Kelly On Behalf Of The American Public Power Association*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, before the Federal Energy Regulatory Commission, Docket No. AD13-7-000, September 9, 2013, p. 16.

> already complex market and would be likely to exacerbate existing market power issues as there are more dominant positions in the smaller submarkets.[120]
>
> Capacity markets provide a powerful economic mechanism to facilitate investment in resources with certain operating characteristics. However, the capacity market should only be used to create such signals when the energy and ancillary services markets do not already provide efficient economic signals supporting the operating characteristic in question. For characteristics that are beneficial in operating the system, well-designed energy and ancillary services markets should fully and efficiently compensate the supplier for the operating characteristic… Additionally, making payments through the capacity market does not guarantee the characteristic will be available during the operations.[121]

Patton says that differences in resources operational characteristics should be recognized through adjustments in the capacity values attributed to different resources rather than through creation of multiple capacity products:

> …different types of resources or quality of resources contribute differently to satisfying the RTOs' planning reserve requirements. For example, a unit with a 20 percent forced outage rate is not equivalent to a unit with a 5 percent forced outage rate. Similarly, intermittent resources with an average load factor of 30 percent are not equivalent to conventional generating resources. Hence, the RTOs generally employ a system to account for these differences. For example, PJM and NYISO calculate translate each unit's installed capacity level into an "unforced capacity" or "UCAP" level that accounts for forced outages and intermittency. While there is room for improvement in how this UCAP translation is implemented, we believe it is far superior to normalize different types of resources into one common product rather than introducing multiple capacity products and corresponding requirements.[122]

While capacity markets do need to be differentiated by location because of deliverability constraints, there is no need to have separate markets for different types of capacity resources. All resources that can enhance power system reliability can and should be accepted as capacity resources. The differentiation among these resources should not be based upon their technologies or their ages, but should be based solely upon their performance: a higher price can be paid to a more valuable resource while a lower price is paid to a less valuable resource; or, equivalently, a higher capacity value can be assigned to a more available and responsive

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[120] *Comments of the Independent Market Monitor for PJM*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, before the Federal Energy Regulatory Commission, Docket No. AD13-7-000, January 8, 2014, p. 8.

[121] *Post-Technical Conference Comments of Potomac Economics Ltd. New York ISO Market Monitoring Unit*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, before the Federal Energy Regulatory Commission, Docket No. AD13-7-000, January 8, 2014, p. 6.

[122] *Id.*, p. 5.

resource while a lower capacity value is assigned to a less available and responsive resource. Resources that can enhance reliability should not be kept out of capacity markets by virtue of their operational limitations; but if those limitations reduce their reliability value relative to other resources, they should be paid a lower price or be assigned a lower capacity value that reflects the reduced reliability value.

For the purpose of providing efficient incentives for resource investment and resource retirement, we offer the following comments relevant to the foregoing proposals:

- If demand-side resources are less available than supply-side resources, they have less reliability value and should be compensated accordingly.
- The value of the quick response of storage resources should be fully compensated in ancillary services markets, not in capacity markets.
- Energy-limited resources, including some demand-side and storage resources, may have less reliability value than resources without this limitation, and should be compensated accordingly.
- Existing and new resources should be compensated differently only to the extent that their operational characteristics give them different reliability values.
- Resources procured through different institutional arrangements – through investment, bilateral contracts, or centralized markets – should be compensated differently only to the extent that the operational characteristics of the underlying resources give them different reliability values.

One of the important lessons learned from the polar vortex experience is the value of fuel diversity, which determines the diversity in the fuel mix of capacity available to maintain grid reliability under extreme weather conditions. Donald Schneider, President of FirstEnergy Solutions, speaking at the FERC technical conference on polar vortex issues, stated:

> You can't have the backbone of the electric system that is counted on for reliability operated on an essentially just-in-time interruptible fuel supply. There is a need to maintain diversity in a fuel supply, and it is particularly important to value on-site fuel optionality… The recent influx of new gas and renewable generation resources has created a challenge for our industry. These new resources do not have the same operational and reliability benefits as essential generation. As market and social forces change the diversity of our fuel mix, it is our responsibility to maintain an even stronger focus on preserving reliability, and this can't be done through planned transmission upgrades alone… The near-term goals should include a mechanism that adequately compensates resources for the value they provide. The longer term goal should be to enhance the

> market construct to maintain on a self-sustaining basis fuel diversity, ensuring that markets maintain a strong focus on reliability.[123]

In keeping with Mr. Schneider's remarks, John Sturm, Vice President of Corporate and Regulatory Affairs, for the Alliance for Cooperative Energy Services (ACES), urged FERC to avoid "additional regulations that might expedite or cause additional coal or nuclear [plant] retirements."[124]

7.2. Reforms in Methods for Meeting Capacity Mandates

7.2.1. Resource Obligations Borne by Distribution Service Providers

Cliff Hamal of Navigant Economics has proposed that capacity resource obligations be borne by distribution wires companies rather than by LSEs.[125] The major motivation for this so-called "BiCap" ("bilateral capacity market") approach is that the "ability for customers to switch suppliers has made it virtually impossible for LSEs to take on long-term obligations to purchase capacity."[126]

Key elements of the BiCap approach include the following:

- Capacity obligations would be the responsibility of distribution companies.
- Existing RTO capacity markets would be eliminated. RTOs would no longer play any role in setting capacity prices, developing capacity demand curves, or dealing with market power.
- RTOs would continue to determine capacity needs based upon NERC standards, peak loads, and deliverability constraints.
- RTOs would assess penalties on distribution companies that fail to meet their obligations.

Hamal claims that placing capacity obligations on distribution companies has the following advantages relative to placing these obligations on LSEs:

- Because load in competitive markets can easily migrate among LSEs but can migrate only with great difficulty among distribution service providers, distribution companies

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[123] Federal Energy Regulatory Commission, *In the matter of Technical Conference On Winter 2013-2014 Operations and Market Performance In RTOs and ISOs*, Docket No. AD14-8-000, Transcript, pp. 210-213.

[124] *Id.*, pp. 229-230.

[125] C. Hamal, *Solving the Electricity Capacity Market Puzzle: The BiCap Approach*, Navigant Economics, July 4, 2013.

[126] *Id.*, p. 3.

are in a better position to make long-term capacity procurement arrangements than are LSEs.[127]

- Because of customers' implicit long-term commitments to their local distribution companies, distribution companies can sign long-term contracts with generators that will allow them to reduce their financing costs by increasing their ability to borrow money long-term.
- Distribution companies can tailor capacity resources to meet their particular local network problems.
- Distribution companies are better able to compare transmission alternatives.

The BiCap approach offers an intriguing solution to LSEs' understandable reluctance to make long-term capacity commitments when they lack long-term purchase commitments from their customers. BiCap also has some weaknesses that arise from its division of capacity rights ownership and capacity needs: capacity rights would be owned by parties (the distribution companies) who are different than the parties who need to exercise those rights (the LSEs). Ideally, capacity would be purchased by parties who balance the costs of capacity with the values of the energy and ancillary services that the capacity can provide, with due consideration of the capacity resource's operating costs and expected availability. Under BiCap, however, the impacts of capacity procurement decisions are bifurcated: distribution providers choose and bear the costs of the capacity, while LSEs bear the operating cost and availability consequences. Distribution providers would therefore have strong incentives to minimize their capacity costs; and they would have only weak incentives to maximize the net value of the services provided by a resource, including consideration of that resource's performance and operating costs relative to market values. In other words, distribution providers might buy the *cheapest* capacity rather than the *best* capacity.[128]

The BiCap approach does address a key weakness of existing capacity markets, namely the absence of truly long-term commitments. Perhaps further development of this approach can address the incentive problems that arise from the division of capacity ownership and capacity needs.

[127] Some commercial and industrial load can migrate among distribution companies by moving production from a site located in one distribution company's service area to another site located in another distribution company's service area.

[128] Some of these concerns may also apply to present RTO capacity markets, wherein LSEs pay for capacity while RTOs exercise the capacity rights. As with the present RTO capacity markets, the problem of capacity quality could be addressed by appropriate capacity performance rules.

7.2.2. Capacity Options

Several authors have suggested that the adequacy problem can be addressed through the forward procurement of reliability options, also referred to as capacity options.[129] These instruments are similar to call options. Whenever the wholesale spot market price exceeds a pre-set reference price (the "strike price"), the contracted capacity supplier must pay the excess to the option owner (such as an LSE). In exchange for writing this option, the capacity supplier receives a fixed capacity payment.

There are three advantages of this capacity option approach. First, the capacity supplier benefits from a stable and predictable income stream. Second, the capacity supplier has a strong incentive for its resource(s) to be available at times of scarcity: if the supplier's resource is not available, the supplier will have to meet the payments under the capacity option contract without receiving any market revenue at a time of high market prices. Third, the buyers of capacity options effectively cap their electricity purchase price at the level of the strike price, since whenever the market price increases above this level, the excess will be "reimbursed" through the payment made by the capacity supplier under the option contract. This provides the buyer with a hedge against spot market price volatility risk.

Capacity options can be designed in a number of ways, depending on whether the scheme is purely financial or also involves an obligation to have and make capacity available when the option is exercised (or otherwise face a penalty). The latter obligation provides assurance that reliability is supported. In such a case, the capacity option becomes similar to a scheme based on capacity obligations. In either case, the capacity option can be priced through a forward auction similar to what the RTOs have in place today.

7.2.3. Treatment of Self-Supply Relative to Centralized Capacity Markets

Until the formation of RTOs, LSEs could meet their capacity obligations through direct investment, shared investment, and bilateral purchase contracts. In the hundred years of power industry history up to the creation of the RTOs, there were no centralized capacity markets.

The creation of the RTOs' centralized capacity markets has been accompanied, in some cases, by requirements that LSEs meet their capacity obligations solely through capacity resources that clear the centralized capacity market auctions. Several representatives of consumers and LSEs have objected that these requirements create potential obstacles to traditional "self-supply" of resources – that is, direct investment in, shared investment in, and bilateral purchase of capacity resources. In cases wherein an LSE procures a self-supplied capacity resource that does not clear in the centralized capacity market auction, the LSE will not only pay for the self-

[129] For example, see P. Cramton, A. Ockenfels, and S. Stoft, "Capacity Market Fundamentals", *Economics of Energy & Environmental Policy*, Vol. 2, No. 2, 2013; and The Agency for the Cooperation of Energy Regulators, *Capacity Remuneration Mechanisms and the Internal Market for Electricity*, July 30, 2013.

supplied resource but will also be forced to pay a substantial penalty to the RTO.[130] The American Public Power Association has asked FERC to "restore the ability of public power systems in the three Eastern RTOs to self-supply their own loads with their own resources."[131]

The National Rural Electric Cooperative Association has said that "the Commission need only satisfy itself that LSEs have a genuine ability to use the capacity resources that they build themselves or acquire in the bilateral market to satisfy their capacity obligations."[132] The Transmission Access Policy Study Group has said that "the Commission should preserve and maximize LSE self-supply and state procurement options."[133]

The opposition to mandatory participation in the RTOs' centralized capacity markets is partly concerned with the inconsistency between the short-term nature of those markets in contrast to the long-term nature of capacity itself. As stated by the Maryland Public Service Commission:

> FERC must preserve the ability of sophisticated buyers and sellers to engage in mutually beneficial long-term transactions. At present, capacity market mechanisms do not provide the signals, nor the opportunity, for developers of new generation to obtain the market assurance they need to commit capital based on a reasonably certain revenue stream required to obtain competitive financing and ensure long-term revenue adequacy. This is precisely where ensuring that willing buyers and sellers can enter into mutually beneficial long-term contracts for capacity and energy will help to remove one impediment to new capacity…[134]

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[130] FERC has recently approved a more lenient self-supply option for PJM, although it has not yet done so in New England or New York. See Federal Energy Regulatory Commission, 143 FERC ¶61,090 (2013), PJM Interconnection LLC, *Order Conditionally Accepting in Part, and Rejecting In Part Proposed Tariff Provisions, Subject to Conditions*, May 2, 2013.

[131] *Written Statement Of Susan N. Kelly On Behalf Of The American Public Power Association*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, before the Federal Energy Regulatory Commission, Docket No. AD13-7-000, September 9, 2013, p. 8. APPA has also offered a broader and more detailed reform proposal, in addition to its first priority of restoring LSEs' self-supply rights. See Section IV (page 61+) of its post-technical conference comments at http://www.publicpower.org/files/PDFs/APPA_Post-Technical_Conference_Comments_AD13-7_Final_1392150690180_2.pdf.

[132] *Post-Technical Conference Comments of the National Rural Electric Cooperative Association*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, before the Federal Energy Regulatory Commission, Docket No. AD13-7-000, January 8, 2014, p. 4.

[133] *Post-Technical Conference Comments of the Transmission Access Policy Study Group*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, before the Federal Energy Regulatory Commission, Docket No. AD13-7-000, January 8, 2014, p. 3.

[134] *Comments of the Maryland Public Service Commission*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, before the Federal Energy Regulatory Commission, Docket No. AD13-7-000, September 9, 2013, p. 8.

Similarly, the Transmission Access Policy Study Group says:

> …the spot capacity market should be residual to LSE self-supply, state procurement, and the longer-term bilateral market. Only markets that provide the potential for long-term commitments to support long-lived, capital-intensive investments are capable of maintaining resource adequacy and meeting other federal, state, and local energy policies. Residual capacity markets are also fully consistent with the Commission's original vision.[135]

Referring to the PJM's capacity market, the PJM Industrial Customer Coalition asserts that:

> RPM should be recognized as a residual procurement. In fact, the descriptor applied to the principal set of annual RPM auctions — the Base Residual Auction — reflects that it was intended to be the process by which capacity would be procured to meet the needs of load after taking account of self-supply.[136]

The APPA also urged the FERC to reform RTO capacity markets by making them "voluntary residual procurement mechanisms… "intended to supplement other, primary methods of procuring capacity (*e.g.,* bilateral contracting or self-builds), and to lay off or procure marginal supply."[137]

Joseph Bowring, head of Monitoring Analytics, PJM's Independent Market Monitor, explains that the value of the centralized capacity markets is that they provide price transparency and thereby encourage efficient provision of capacity:

> A single central capacity market is clearly preferable to a series of bilateral contracts… The capacity market is transparent and market outcomes reflect supply and demand fundamentals. A bilateral market is opaque to market participants and provides opportunities to exercise market power in the presence of very little information about market fundamentals and likely significant asymmetries in access to information.[138]

Bowring explains that the RTOs' centralized capacity markets cannot serve as residual markets, particularly if LSEs finance their self-supply through traditional cost-of-service regulation:

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[135] *Post-Technical Conference Comments of the Transmission Access Policy Study Group*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, before the Federal Energy Regulatory Commission, Docket No. AD13-7-000, January 8, 2014, p. 15.

[136] *Post-Technical Conference Comments of the PJM Industrial Customer Coalition*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, before the Federal Energy Regulatory Commission, Docket No. AD13-7-000, January 8, 2014, p. 14.

[137] *Written Statement Of Susan N. Kelly On Behalf Of The American Public Power Association*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, before the Federal Energy Regulatory Commission, Docket No. AD13-7-000, September 9, 2013, pp. 63-64.

[138] *Comments of the Independent Market Monitor for PJM*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, before the Federal Energy Regulatory Commission, Docket No. AD13-7-000, January 8, 2014, p. 12.

> A residual market by definition relies on other mechanisms to acquire capacity. If the other mechanism is cost of service regulation, then the residual market will not result in a price that reflects the fundamentals of supply and demand conditions. Such a residual market is very unlikely to result in incentives adequate for a merchant generator to profitably build new generation.[139]

He therefore finds that the RTOs' centralized capacity markets cannot properly function if participation in those markets is not mandatory:

> The most important point about all the approaches to the net revenue problem is that they are mutually exclusive. If a market chooses the cost of service paradigm based on state regulated cost of service revenue guarantees, it makes it impossible to have a competitive capacity market. It is not possible for a competitive merchant generation developer to compete with such revenue guarantees.[140]

Again, all resources that can enhance power system reliability can and should be accepted as capacity resources; and the value of those resources should be based solely upon their performance, not on the means by which they are acquired. The RTOs' centralized capacity markets are problematic because they are so short-term: by design, they cannot be expected to support long-term investment. Making participation in the centralized markets mandatory has the perverse effect of creating incentives that undermine long-term investment and that, in particular, undermine a capacity investment model that has worked well, if imperfectly, for over a century. Mandatory participation also limits LSEs' ability to fashion solutions that fit their own individual situations, or increases LSE's costs of doing so.

7.2.4. Reform of LMP Pricing

Because resource investments depend upon energy and ancillary services prices, those prices need to be efficient. Unfortunately, energy and ancillary services prices are inefficiently reduced by public policies that support particular types of resources (e.g., renewable resources) and by RTO actions to support power system security through out-of-market purchases of energy and ancillary services. The Electric Power Supply Association explains the latter problem as follows:

> …LMPs are understating the revenue required to reliably meet demand for electricity in wholesale markets. This occurs when grid operators frequently take actions without transparency and accountability to call on resources outside of economic merit order that are compensated other than through LMPs. Instead, these other resources are paid through what is called uplift, a cost that is spread among load outside of the LMP mechanism. By definition, the resulting LMPs when this occurs understate the amount of revenue necessary to serve the

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[139] *Id.*, p. 12.

[140] *Id.*, p. 13.

system because the LMPs do not include the cost of taking all of the actions actually taken in the name of reliability but paid via uplift instead. This significantly mutes the price signals including forward prices on which investment decisions are based resulting in muted investment relative to what is required in a competitive market.[141]

The reductions in energy prices can result in significant revenue loss for generators and reduced incentives for needed investment. As the Electric Power Supply Association states, the determination of LMPs should be reformed so that all resources receive higher energy prices when the RTOs find it necessary to make out-of-market payments to support reliability.

8. CONCLUSIONS

The U.S. electric power industry has a one-hundred-year history of providing capacity resources that have been adequate under all but the most extreme conditions. The main contributor to this favorable outcome has been a set of power industry business practices that require resources to exceed peak loads according to certain engineering-based analyses or rules of thumb. These industry practices have been supplemented and strengthened by various state proceedings such as integrated resource planning.

While traditionally regulated electricity markets have issues such as contentious prudence determinations, these markets continue to meet resource adequacy requirements under the supervision of state regulators.

The current debate on resource adequacy arises primarily from questions about how to make the restructured markets' model work. These questions arise from the following fundamental causes:

- *RTOs' short-term centralized capacity markets do not provide incentives for long-term resource investments*. These markets were designed to improve the short-term commitment and dispatch of power system resources; and for this short-term purpose, they have been very successful.[142] But these RTO markets, being short-term markets, do not and cannot address long-term capacity needs. In the words of one of the prominent advocates of these markets, "Many in the industry confuse RTOs' mandatory forward procurement with longer-term forward contracting. *They are not substitutes*;

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[141] *Comments of the Electric Power Supply Association*, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, before the Federal Energy Regulatory Commission, Docket No. AD13-7-000, January 8, 2014, p. 12.

[142] The engineering-economics basis for electricity restructuring in general and for LMP calculations in particular is entirely short-term. For one of the original articles describing this basis, see R.E. Bohn, M.C. Caramanis, and F.C. Schweppe, "Optimal Pricing in Electrical Networks Over Space and Time", *Rand Journal of Economics*, 15(3): 360-76, Autumn 1984. A more comprehensive description can be found in F.C. Schweppe, M.C. Caramanis, R.D. Tabors, and R.E. Bohn, *Spot Pricing of Electricity*, Kluwer Academic Publishers, Boston, 1987. The mathematics of the RTOs' present energy and ancillary service price determinations are elaborations of the ideas presented in these publications.

Bilateral forward contracting remains key under any market design for locking in revenues and facilitating financing of new resources."[143] Contrary to this key necessity, however, the RTO markets include some design elements that impede long-term investments and long-term bilateral contracts.

- *The political process will not allow peak-period demand pricing or rationing that is consistent with a market solution*. Specifically, the RTOs' energy and ancillary services prices are capped by politically risk averse regulators; and on the rare occasions when non-price rationing (e.g., rolling blackouts) occurs due to capacity shortfall, that rationing does not tend to discriminate between those consumers and retail suppliers who arrange adequate supplies and those who do not.
- *Electricity customers are generally not willing to pay explicit prices consistent with the high cost of building the resources that are required to avoid peak-period demand rationing*. In particular, the one-event-in-ten-year rule of thumb has an incremental cost that is far above many customers' willingness to pay for reliability. Outage costs do vary widely among customers. Nonetheless, because customers' willingness to pay for reliability is generally well below that needed to support the power industry's usual planning reserve requirements, markets alone will not support the capacity requirements implied by the power industry's reliability practices, even with a perfectly functioning demand-side of electricity markets.

These fundamental causes imply that the resource adequacy problem does not have a market solution. The RTOs, as they struggle to fit a square peg into a round hole, must therefore continually reform their capacity markets, sometimes in major ways, always through contentious proceedings, as they search for a market solution that cannot exist under existing political and regulatory frameworks. While a well-functioning market attracts participation because that market provides trades on terms that are comparable to or better than those available through other venues, the RTOs' centralized capacity markets tend to be mandatory because, as many parties have indicated, there are venues in which capacity services are available on better terms than are available in the RTOs' centralized capacity markets. There are few places in the American economy wherein one can find a free market in which participation is mandatory.

The traditionally regulated markets avoid all the foregoing problems by simply not attempting a market solution, except to the extent that they have competitive bidding procedures to meet identified capacity needs.

There are additional matters that should be, and indeed already are, of great concern to policymakers and all stakeholders in the electric power industry:

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[143] D.B. Patton, *Resource Adequacy in Wholesale Electricity Markets: Principles and Lessons Learned*, Federal Energy Regulatory Commission Technical Conference on Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, Docket No. AD13-7-000 September 25, 2013, p. 8.

- The reliability of some portions of the power system has been challenged by a lack of fuel diversity in new generation development. The cold winter of 2013-2014 (the “polar vortex”) and the accompanying gas price spikes and gas delivery issues highlight the perils of over-reliance on any one fuel.
- Gas-electric coordination has become increasingly important as we rely more on natural gas. Questions arise as to whether generation can be counted as firm capacity if it does not have firm transportation contracts. Again, the polar vortex was a demonstration of the possible implications of insufficient firm transportation.
- The planned retirement of coal plants (for both economic and environmental reasons), the retirement of two nuclear plants for economic reasons, and the possible retirement of more nuclear plants will exacerbate the resource adequacy problem in most RTOs, creating significant reliability concerns.
- There is reasonable concern about the capacity value of demand-side resources. It is risky to over-rely on these resources until they have been thoroughly tested by experience.
- There is reasonable concern about the capacity value of intermittent resources, and about the power system control and security problems raised by their intermittency.

There have been many proposals made to reform capacity markets or to design new methods to ensure resource adequacy in the restructured markets, but most of these proposals assume that tweaks to the restructured market model will be sufficient. A more comprehensive solution is necessary, however. For example, the restructured markets could be designed so that capacity is procured in ways similar to those used in traditional regulated markets: set capacity requirements according to engineering criteria; impose high penalties on those LSEs who fail to meet their requirements; and offer a centralized market for those parties who find the centralized market’s terms attractive. Generation could be procured through competitive solicitation as it is done successfully in some traditionally regulated markets as well as in some restructured markets. And RTOs could continue to operate energy markets in the same way as they do today.

Our nation needs to continually strive for better regulatory and market rules that ensure resource adequacy at reasonable cost to consumers and the economy. We recommend that regulators and legislators, at both the federal and state levels, closely examine the resource adequacy problem in restructured markets and develop solutions soon. Because of the significant time that is required to develop new resources, we cannot afford to wait until resource adequacy problems become more acute.