FINANCIAL ARRANGEMENTS BEHIND NEW GENERATING CAPACITY and Implications for Wholesale Market Reform

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Introduction

This paper provides an analysis of the types of financial arrangements behind new electric generation capacity that completed construction and came online in 2016 and 2017. While there are extensive data available on the types of technologies being constructed each year, there are limited aggregated data on the financial arrangements behind the construction of these technologies. Such data show how new generation resources are developed within the different types of electricity market and regulatory structures throughout the country, and specifically provide one important data point to assess the performance of the capacity markets operated by the Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), herein collectively referred to as RTOs.

Before presenting the data, the next section provides an overview of the RTO-operated capacity markets and recent developments in those markets. The third section analyzes the data on the financial arrangements behind new generating capacity that began service in 2016 and 2017, the fourth section delves into the growth of new merchant generation, and the final section contains recommendations for capacity market reform.

The key findings of the data analysis are:

- While fluctuating somewhat, merchant generation has accounted for an increasing share of new capacity, equal to 5 percent in 2014, 19 percent in 2015, 7 percent in 2016, and 29 percent in 2017. (Merchant generation projects are those funded only by revenue from sales into the wholesale markets.)

- Capacity constructed under bilateral contracts accounted for half of the new capacity built in 2016 and 2017, and was predominantly wind and solar.

- Just under one-third of the new capacity is owned and operated by a utility or end-user, the majority of which are natural gas resources.

- Merchant generation that came online in the past two years was almost entirely within the PJM Interconnection and Texas.

- Utility-developed new capacity shows a much greater diversity than the merchant projects, with roughly one-third natural gas, one-third solar, and another quarter wind. In contrast, new merchant capacity is 86 percent natural gas and 12 percent wind, with a small amount of storage and solar.

- Hydropower and nuclear power are not present in the merchant projects but represent just under two and four percent, respectively, of the utility projects.

- The lack of generating technology diversity within the new merchant generation stands in contrast to increasing efforts by the states and the RTOs to address environmental, resource diversity, and fuel security goals.

- While the growth of merchant generation demonstrates that new capacity can be developed by relying solely on the RTO-operated capacity and energy markets, many questions remain about the benefits of a merchant model.

Background on RTO-Operated Capacity Markets and Recent Developments

While the data presented encompass all capacity constructed in the United States, the focus of this paper is on the RTOs that operate capacity markets and are comprised primarily of retail choice states — PJM Interconnection (PJM), ISO New England (ISO-NE), and the New York ISO (NYISO), collectively referred to as the “Eastern RTOs.”

This paper focuses on these RTOs because of the ongoing discussion and debate within these regions about the best model for achieving resource adequacy. Because most investor-owned utilities in the Eastern RTOs have been restructured as part of the state retail access programs, and no longer own generation, decisions to construct new generating capacity or retire capacity are often made by non-utility independent power producers, and by those utilities that remain vertically integrated.

These remaining vertically integrated utilities are public power and electric cooperative utilities, as well as investor-owned utilities within the regulated states located in the Eastern RTOs – Vermont, Virginia, and West Virginia, plus the Eastern Kentucky Power Cooperative service territory and very small areas of North Carolina and Tennessee within PJM. These entities are permitted to construct or contract for capacity, retain an obligation to serve customers, and are regulated either by state commissions, in the case of the IOUs, or local governing bodies, in the case of public power and cooperative utilities.

In contrast, non-utility independent power producers do not have an obligation to serve customers, are not subject to state utility commission authority, and do not participate in integrated resource planning. These entities may sell capacity and energy from their generation on a pure merchant basis or under contract to a utility, retail supplier, or end user.

Overview of Eastern RTO Capacity Markets

The Eastern RTOs all operate capacity markets and conduct regular capacity auctions in which supply and demand-side resources offer their capacity for sale for a given period of time. Resource offers to sell capacity that are at a price below the clearing price clear the auction and the seller receives a capacity supply obligation. Only resources that clear the auction can be counted toward a load-serving entity’s reliability obligation.[1]

Resources owned or under contract to a load-serving entity must still be offered into and clear the capacity auctions. If a resource has a payment stream outside of the capacity market, the logical course of action for the owner is to offer such capacity into the auction at a zero price to ensure clearing regardless of the capacity price.

PJM and ISO-NE both operate a “forward” market where capacity is procured in the auctions three years in advance for a one-year period. Capacity auctions in NYISO are shorter term and procure capacity at least thirty days prior to six-month Winter and Summer capability periods, and are also held on a monthly and spot basis. Only the auctions within the New York City and Lower Hudson Valley are mandatory.

The RTOs justify the capacity markets as needed to provide revenue and price signals for the development and retirement of generating capacity, as well as demand-side resources, to ensure reliability. PJM describes its capacity market, the Reliability Pricing Model (RPM), as follows:

> Investors need sufficient long-term price signals to encourage the maintenance and development of generation and other resources. The RPM, based on making capacity commitments three years ahead, creates long-term price signals to attract needed investments in reliability in the PJM region.[2]

[1] A load-serving entity is a utility or other entity, such as an alternative retail supplier, with an obligation to provide electricity to end-users.
[2] *Reliability Pricing Model Fact Sheet*, PJM Interconnection, LLC, updated June 1, 2017.

Similarly, ISO-NE makes the following statement about its Forward Capacity Market:

> The Forward Capacity Market (FCM) ensures that the New England power system will have sufficient resources to meet the future demand for electricity… [Capacity] payments help support the development of new resources. Capacity payments also help retain existing resources. For example, they incentivize investment in technology or practices that help ensure strong performance. They also serve as a stable revenue stream for resources that help meet peak demand but don't run often the rest of the year.[3]

The NYISO explains that the "markets are designed to send appropriate price signals for new market entry of resources that may assist in maintaining reliability,"[4] and the NYISO's market monitor explains that the installed capacity market supplements the energy and ancillary services markets and "provides incentives to satisfy NYISO's planning reliability criteria over the long-term by facilitating efficient investment in new resources and retirement of older uneconomic resources.[5]

Two sets of developments within the Eastern RTOs have affected and will continue to affect the capacity market rules: 1) the increase in state actions to promote or support specific resources, and the expansion of buyer-side mitigation rules in response; and 2) increased attention to resilience and fuel security. Both are described below.

Growth of State Actions and Buyer-Side Mitigation

Several years after implementation of the capacity markets in PJM and ISO-NE in 2007 and 2008 respectively,[6] states within the Eastern RTOs began to implement measures to develop specific types of new capacity. Most notable were the establishment of competitive bidding processes in New Jersey and Maryland for new natural gas units that would sign 15-year contracts with the regulated distribution utilities.[7] The Maryland and New Jersey programs were later invalidated, however, in the Supreme Court's Hughes v. Talen Energy Marketing decision.[8]

In New England, several states have procured renewable energy through long-term contracts, including an effort pursuant to a 2016 Massachusetts bill that requires the competitive solicitation and procurement of 1,200 megawatts (MW) of renewable energy (including hydropower) and 1,600 MW of offshore wind.[9] In addition, Connecticut, Massachusetts, and Rhode Island have solicited renewable energy projects to sign long-term contracts through the Clean Energy RFP.[10]

A second wave of state actions were directed not at the development of new resources but at preventing the retirement of existing resources, specifically nuclear power plants through the payment of "zero emission credits" or "ZECs." ZEC payment programs are in place in Illinois and New York,[11] and processes for approving and awarding ZECs to nuclear plants have been established in New Jersey[12] and Connecticut.[13]

3 Forward Capacity Market, ISO-New England website, visited May 20, 2018.
4 *2016 Comprehensive Reliability Plan*, NYISO (April 2017) at 2.
5 *2017 State of the Market Report for the New York ISO Markets*, Potomac Economics (May 2018), at i.
6 Capacity auctions began in the NYISO in 2000.
7 New Jersey P.L. 2011, c. 9, (known as the "LCAPP Law"), signed by Governor Chris Christie on January 28, 2011, Order No. 84815, *In the Matter of Whether New Generating Facilities Are Needed to Meet Long-Term Demand for Standard Offer Service*, Case No. 9214, Maryland Public Service Commission (Apr. 12, 2012).
8 *Hughes, Chairman, Maryland Public Service Commission, et al. v. Talen Energy Marketing, LLC, fka PPL EnergyPlus, LLC, et al.* 136 S. Ct. 1288 (Decided April 19, 2016).
9 Chapter 188 of the Acts of 2016, Massachusetts, signed by Governor Charlie Baker on August 8, 2016.
10 See https://cleanenergyrfp.com/
11 Public Act 099-0906, Illinois, signed by Governor Bruce Rauner, December 7, 2016; *Order Adopting a Clean Energy Standard*, State of New York Public Service Commission, Cases 16-E-0270 and 15-E-0302 (August 1, 2016).
12 P.L.2018, c.16, signed by Governor Phil Murphy, May 23, 2018. To receive the ZECs, a nuclear plant would need to demonstrate that they contribute to the air quality of the state by minimizing emissions, and that its fuel diversity, air quality and environmental attributes are at risk due to the plant's inability to cover its costs.
13 The Connecticut Department of Energy and Environmental Protection (DEEP) and Public Utility Regulatory (PURA) Authority announced their intent to conduct a procurement or procurements for new and existing zero-emission generating facilities. Existing resources may petition the PURA to participate in the procurement if they are at risk of retirement. *DEEP and PURA Joint Proceeding to Implement the Governor's Executive Order Number 59*, Notice of Close of Proceeding, Docket No. 17-07-32, April 30, 2018.

Merchant generators depend upon revenue from the energy and capacity markets to sustain their earnings, and have therefore aggressively (and often successfully) advocated for market rules that will protect the capacity market prices from these state actions. The Eastern RTOs all have some form of "buyer-side mitigation" or a "minimum offer price rule (MOPR)" that applies a floor on the capacity offer price of new resources in the auctions (although in PJM, the MOPR only applies to new natural gas-fired resources). Such rules do not only apply to resources developed under state programs. Generating capacity developed by public power and cooperative utilities, also known as self-supply resources, have also been subject to these mitigation rules in the Eastern RTOs, other than during the five years when a self-supply exemption from the MOPR was in place within PJM.[14]

The original rationale provided by the RTOs for buyer-side mitigation measures was to protect the capacity markets from what is termed "buyer-side market power," or the theoretical strategy of developing new resources as a means to lower prices. More recently, these measures are being described more broadly as needed to prevent capacity price suppression from what are termed "out-of-market" payments. Revenue from a utility contract implemented under a state program, for example, allows the resource to participate in the auction as a price taker and enter a zero or low-priced bid because the resource is earning payments "outside the market" and is therefore indifferent to the market clearing price. Supporters of price mitigation argue that capacity market prices are essential to sending proper price signals to merchant generation. According to this argument, low or zero bids from the state-sponsored resource, for example, distort the price signals and harm reliability by preventing the development of new resources,[15] even though the state actions to create new resources would obviate the need for merchant generator development of new resources.

While the current mitigation rules address new resource development, based on the initial rationale of preventing buyer-side market power, the RTOs, merchant generators, and the Federal Energy Regulatory Commission (FERC) are seeking to apply mitigation to "out-of-market" efforts to preserve existing resources. For example, FERC recently issued an order proposing a preliminary tariff change for PJM that would expand the MOPR to include all existing generating resources, regardless of resource type.[16]

Grid Resilience and Fuel-Security

Thus far, the Eastern RTOs have not faced any difficulty in meeting and even surpassing reliability standards, and have been procuring capacity above their reserve margin requirements.[17] Such excess procurement first raises the question of whether consumers are funding capacity beyond what is required. Moreover, state actions taken to support certain resources demonstrate that the capacity procured through the auctions, while providing a sufficient reserve margin, does not necessarily meet specific policy needs. Some RTOs have recently raised the question of whether the reliability standards are sufficient and if the RTOs should also establish goals or standards for "resilience" and the related concept of "fuel security."

[14] When the RPM was first created in 2006, PJM's tariff language allowed for self-supply resources to clear the auction prior to other capacity resources. FERC in 2011 then removed this "guaranteed clearing" provision by clarifying that self-supply bidding as a Planned Generation Resource is subject to the MOPR (*PJM Interconnection, LLC* 135 FERC ¶ 61,022 (2011) at P 191). In May 2013, the Commission accepted PJM's filing of a self-supply categorical exemption (along with a competitive entry exemption) from the MOPR, and conditioned such acceptance upon the inclusion of a unit-specific review provision (*PJM Interconnection, LLC*, 143 FERC ¶ 61,090 (2013) at P 141). In July 2017, the US Court of Appeals for the D.C. Circuit order (*NRG Power Marketing, LLC v. FERC*, 862 F.3d 108, 117 (2017)) vacated, in part, and remanded back to FERC the 2013 order and a subsequent order on rehearing (*PJM Interconnection, LLC*,153 FERC ¶ 61,066 (2015)). The Commission issued an order on remand later that same year retaining the unit-specific review but finding that the categorical exemptions for self-supply (and for competitive entry) are not just and reasonable (*PJM Interconnection, LLC* 161 FERC ¶ 61,252 (2017) at P 48.

[15] For example, when seeking a tightening of the MOPR applicability in 2011, PJM argued that the RPM "rules also must ensure that market participants cannot use uncompetitively low new entry offers to suppress clearing prices, which can deter new entry even in parts of the system where it may be required." Filing of Revisions to the PJM Open Access Transmission Tariff, PJM Interconnection, Federal Energy Regulatory Commission (February 11, 2011).

[16] *Calpine et al. vs. PJM Interconnection, LLC*, Consolidated,163 ¶ 61,236 (June 2018).

[17] PJM's most recent Base Residual Auction procured capacity sufficient to provide a reserve margin of 21.5 percent or 5.7 percentage points higher than the target reserve margin of 15.8 percent, *2021/2022 RPM Base Residual Auction Results*, PJM Interconnection, May 23, 2018; ISO-NE's 12th Forward Capacity Auction procured an excess of 1,103 MW above the reserve margin, *Forward Capacity Auction #12 Results Summary*, ISO-New England, May 28, 2018; and the NYISO estimates a baseline reserve margin of 28.4 percent in 2018 compared to a required reserve margin of 18.2 percent, *Load and Capacity Data Report or 2018, Gold Book*, NY ISO, Table V-2a and notes (April 2018).

FERC proposed a definition of resilience as the "ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event."[18] Fuel security is one facet of resilience, and addresses the ability of the bulk power system to withstand the potential disruption of the supply of one type of fuel, such as a natural gas pipeline outage. The concept of fuel security involves having a generation portfolio that includes a diversity of resource types, as well as resources with onsite fuel or alternative fuel sources. Some recent Eastern RTO actions on resilience and fuel security are:

- ISO-NE released an analysis in January 2018 of a range of scenarios for the winter of 2024-2025 and found that the potential risk of energy shortages due to inadequate fuel was present in almost all scenarios.[19]

- In early May, ISO-NE asked FERC to approve a waiver of the current rules for Reliability-Must-Run (RMR) agreements to retain two natural gas units needed for fuel security because the units use liquified natural gas from a terminal, rather than relying on natural gas pipelines. ISO-NE is requesting a waiver of its tariff because the current RMR rules only cover local transmission reliability, not the retention of units to address fuel security risks. FERC rejected the waiver request but directed ISO-NE to submit interim rules for short-term cost of service agreements to address fuel security concerns, and permanent market design improvements to better address regional fuel security. Alternatively, ISO-NE could show cause that its current rules remain just and reasonable.[20]

- PJM released a paper in March 2017 that found: "Heavy reliance on one resource type, such as a resource portfolio composed of 86 percent natural gas-fired resources, however, raises questions about electric system resilience, which are beyond the reliability questions this paper sought to address."[21]

- PJM recently proposed to first model and then incorporate fuel security risks as constraints in the capacity market in a manner that is analogous to how transmission constraints are currently modeled.[22]

- While NYISO has not expressed the same level of concern about fuel security, noting that 84 percent of the natural-gas fired resources in the state have dual-fuel capability,[23] the ISO reports that it is assessing whether procurement of additional and different types of capacity is needed. Specifically, NYISO is working with stakeholders to assess implementation of "a construct that provides appropriate incentives to procure additional operating reserves in excess of the established and recently enhanced minimum requirements," and to "evaluate the potential need for a separate ramping product or modifications to the current operating reserve products to effectively and efficiently respond to increased net load forecast uncertainty."[24]

The capacity auctions were not designed to select resources according to type of technology. In contrast, resource decisions by state commissions and legislatures, public power and cooperative utilities, are more often driven by specific policy goals. Both the state procurements and resource payments, and the RTO actions and statements on resilience and fuel security, demonstrate an increasing awareness that not every megawatt of capacity is the same, and that the mix of resources being developed within the Eastern RTOs may not achieve a range of policy goals, whether the goal is fuel security, resource diversity, flexibility, or environmental targets.

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18 *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, 162 FERC ¶ 61,012 (2018) at 13.

19 *Operational Fuel-Security Analysis*, ISO-New England (January 2018).

20 *Petition of ISO New England Inc. for Waiver of Tariff Provisions*, Docket ER18-1509, Federal Energy Regulatory Commission (May 1, 2018); ISO New England, Inc., 164 FERC ¶ 61,003 (July 2018).

21 PJM's Evolving Resource Mix and System Reliability, PJM Interconnection LLC at 4 (March 2017).

22 *Valuing Fuel Security*, PJM Interconnection, LLC (April 30, 2018).

23 *Response of the New York Independent System Operator, Inc,* Docket AD18-7, Federal Energy Regulatory Commission (March 9, 2018) at 31.

24 *Id.* at 30.

Other Market Types

Outside of the Eastern RTOs, California and Texas are two other states that implemented retail choice, although neither the California ISO nor the Electric Reliability Council of Texas (ERCOT) has a capacity market. Although California did implement retail access, the state commission greatly restricted customer participation in retail choice following the energy crisis of 2000 and 2001. Unlike the Eastern RTOs, the utilities in California are a primary source of resource procurement. Load-serving entities in California are required to submit long-term procurement plans to the Public Utilities Commission to demonstrate how reliability standards will be achieved through long-term contracts or the construction of utility-owned resources.

Texas restructured its retail market but does not have a capacity market. Instead, ERCOT uses shortage pricing as a mechanism to incent new resource development, where prices can rise as high as $9,000 per megawatt-hour during shortfalls in operating reserves.

The remainder of states are either outside of RTOs, in an RTO with a voluntary capacity market (Midcontinent Independent System Operator or MISO), or in an RTO with no capacity market (Southwest Power Pool or SPP).

Financial Arrangements Behind 2016 and 2017 New Generating Capacity

This section provides data on new generating capacity constructed and brought online in 2016 and 2017 according to technology type and financial arrangement. Individual year data is provided in the Appendix.

There are three basic types of financial arrangements:

Bilateral contracts: A contract between the owner of the resource and a utility or end-use customer for the purchase of power, renewable energy credits, or net metering credits. Also included are financial hedges, discussed later in this section.

Ownership: Where the utility finances and owns the generation resource for the provision of electricity to its customers, and recovers the cost of financing, constructing, and operating the resource from ratepayers. This category also includes the construction and ownership of a resource by an end-user, such as a factory, university, or hospital, for supplying its own electricity needs.

Merchant Generation: These resources earn all the revenue needed to cover their costs, plus profits, through sales into the wholesale markets. Merchant generation has no guaranteed stream of revenue.

In addition to these three categories, community solar is treated as a separate category. According to the Smart Electric Power Alliance (SEPA), for two-thirds of community solar capacity, a third-party, non-utility entity constructs the solar facility and administers the program.[25] For the remaining projects, the utility owns or contracts for the capacity and in turn offers shares to its customers. The exact arrangement behind the community solar resource was not always available and is therefore listed as a separate category.

Sources of Data

The list of new generating units, technology type, location, and capacity were obtained from the Energy Information Administration (EIA).[26] EIA data exclude capacity below one megawatt (although there are a few units with a capacity between 700 and 900 kilowatts), and therefore does not include residential rooftop solar. The capacity data also include projects on the distribution system and thus, the information is not limited to units that participate in the wholesale markets.

The capacity data are provided as net summer capacity, defined by EIA as the “maximum output, commonly expressed in megawatts (MW), that generating equipment can supply to system load, as demonstrated by a multi-hour test, at the time of summer peak demand (period of May 1 through October 31). This output reflects a reduction in capacity due to electricity use for station service or auxiliaries.”

Information on the financial arrangements behind the new capacity was primarily obtained from utility and developer websites, trade and local press, the monthly Energy Infrastructure Update issued by FERC, and the Wind Industry Fourth Quarter Market Reports for 2016 and 2017 published by the American Wind Energy Association.[27]

Past Analyses

Following the implementation of retail restructuring and creation of RTOs in the late 1990s and the emergence of capacity markets in 2006 and 2007 in ISO-NE and PJM, there was no evidence that developers would build new generation without a guaranteed stream of revenue, as provided for in a long-term bilateral contract or ownership. As shown in Table 1, as recently as 2014, the vast majority of new capacity was constructed under long-term bilateral contracts or utility or customer ownership, with almost no project developers choosing to rely on more volatile wholesale market revenues.

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25 *Community Solar Design Models*, Smart Electric Power Alliance (2018).

26 Table 6.3, New Utility Scale Generating Units by Operating Company, Plant, Month, and Year, Electric Power Monthly from February 2018 and February 2017, US Energy Information Administration

27 Where no information was available, if the project was in a restructured state it was assumed to be a merchant project, and if it was in a vertically-integrated state, it was assumed to have a contract with a utility. Units without any available information were all small and totaled less than one percent of all new capacity.

Table 1. Total New Capacity and New Merchant Generation, 2013 – 2017

Year	Total New Capacity	New Merchant Capacity	% Merchant
MW of Net Summer Capacity			
2013	14,680.3	348.0	2.4%
2014	17,638.2	839.9	4.8%
2015	18,316.9	3,531.6	19.3%
2016	28,355.8	2,037.0	7.2%
2017	21,347.0	6,212.8	29.1%

Beginning in 2015, merchant generation began to increase dramatically from prior years. In that year, 2,400 MW of new merchant natural gas plants came online in PJM and another 330 MW of new merchant natural gas and 550 MW of new merchant wind began operating in Texas, plus a small amount of storage and solar projects.

New merchant generation in PJM in 2015 included the 685 MW Newark Energy Center and 700 MW Woodbridge Energy Center, which were initially awarded 15-year Standard Offer Capacity Agreements (SOCAs) under the New Jersey Long Term Capacity Agreement Pilot Program (LCAPP).[28] Because the SOCAs have been invalidated by the Supreme Court's decision in Hughes v. Talen, these plants shifted their cost recovery from long-term contract revenues to market revenue and were refinanced, but it is not known if these projects would have been undertaken in the absence of LCAPP. Two other merchant plants in PJM — the 110 MW Perryman 6 natural gas plant and the 30 MW Fair Wind Energy Project — were constructed in accordance with Exelon's commitment to Maryland under the agreement on the company's merger with Constellation.[29]

Not only is the share of merchant capacity increasing, but the total capacity constructed nationwide has been increasing steadily, even though electricity demand by end users declined by two percent in between 2016 and 2017 and remained flat between 2015 and 2016.[30] Retirements of capacity amounted to 12,712 MW in 2016 and 11,229 MW in 2017,[31] both significantly below the new capacity constructed in each year. This mismatch is likely due to state, local, and business decisions to shift the types of capacity used to generate electricity, rather than a focus on the sufficiency of the total amount of capacity.

New Capacity in 2016 and 2017

Table 2 provides a summary of the financial arrangements for the new capacity that began operating in 2016 and 2017. As shown, half of the new capacity constructed in the past two years was built under a bilateral contract. Renewable energy accounts for close to 98 percent of the contracted capacity. Information on the term of the contracts was not always available, but generally the contracts have a length of about 20 years.

Another 30 percent of the new capacity was constructed by the owner, with natural gas representing about 70 percent of this category. There were also two utility-owned nuclear projects completed in 2016 and 2017. The Tennessee Valley Authority completed the Watts Barr Unit 2 in 2016, with a capacity of 1,122 MW, and Indiana-Michigan Power upgraded the Donald Cook Nuclear Plant Unit 2 in 2017, as part of the renewal of the unit's Nuclear Regulatory Commission license, adding 102 MW.

[28] LCAPP Agent's *Report*, Prepared for the New Jersey Board of Public Utilities (NJPBU), Levitan & Associates (March 2011). The recommendations contained in the LCAPP Agent's Report were approved by the NJBPU on March 29, 2011.

[29] "Exelon Generation's New Maryland Natural Gas Power Plant Now Operational," Exelon Press Release, June 25, 2015, stating that "Exelon had committed to increasing natural gas generation in Maryland as part of the company's 2012 merger with Constellation…Earlier this year, Exelon Generation fulfilled another merger commitment with the completion of the 40-megawatt Fourmile Wind Project. Construction is under way on Fair Wind Energy Project, a 30-megawatt wind project."

[30] Table 7.6, Electricity End Use, May 2018 Monthly Energy Review, US Energy Information Administration shows that the total end use of electricity was 3.82 billion megawatt-hours in 2017, 3.902 in 2016 and 3.900 in 2015.

[31] Table 6.4, Retired Utility Scale Generating Units by Operating Company, Plant, Month, and Year, Electric Power Monthly from February 2018 and February 2017, US Energy Information Administration.

Storage capacity accounts for less than one percent of the new capacity in 2016 and 2017, and has been increasing in recent years. New storage capacity is spread evenly among the three types of financial arrangements. A total of 446 MW of storage was deployed in 2016 and 2017, according to the US Energy Storage Monitor,[32] which is about 120 MW more than the storage reported by EIA. The difference is likely due to the prevalence of smaller projects that may not be included in the EIA data.

Community solar, while expanding rapidly, accounted for less than one percent of the total new capacity. SEPA reports that approximately 387 MW of community solar was installed in 2017,[33] and the EIA data shows about 265 MW in that year. The difference may reflect the fact that 70 percent of the utility community solar programs are below one megawatt and therefore not reported by EIA, as well as the likelihood that some of the capacity constructed under a utility contract or ownership may be a community solar project. This is especially likely for public power community solar.

Finally, almost 17 percent of the new capacity was merchant generation. Of this, 86 percent is natural gas and the remainder is wind, with small amounts of storage and solar.

Table 2. Summary of Financial Arrangements behind New Capacity, 2016-2017

Arrangement	Hydropower	Natural Gas	Nuclear	Solar	Storage	Wind	Other*	Total	% of Total
MW of Net Summer Capacity									
Contracts	7.2	329.2	-	11,600.5	105.6	13,360.3	167.5	**25,570.3**	**51.5%**
Percent of Contracts	0.03%	1.3%	-	45.4%	0.4%	52.2%	0.7%	100%	
Ownership	579.7	11,086.0	1,224.0	1,118.7	116.9	1,133.8	251.5	**15,510.6**	**31.2%**
Percent of Ownership	3.7%	71.5%	7.9%	7.2%	0.8%	7.3%	1.6%	100%	
Community Solar	-	-	-	372.1	-	-	-	**372.1**	**0.7%**
Merchant	**-**	**7,107.2**	**-**	**39.9**	**104.4**	**998.3**	**-**	**8,249.8**	**16.6%**
Percent of Merchant	-	86.1%	-	0.5%	1.3%	12.1%	-	100%	
Total	**586.9**	**18,522.4**	**1,224.0**	**13,131.2**	**326.9**	**15,492.4**	**419.0**	**49,702.8**	
% of Total	**1.2%**	**37.3%**	**2.4%**	**26.4%**	**0.7%**	**31.2%**	**0.84%**	**100%**	

*Other includes biomass, coal, fuel cells, geothermal, landfill gas and petroleum. The only new coal developed was a 50 MW upgrade of an electric cooperative unit in Alaska.
Shaded areas indicate the greatest component of each category.

[32] GTM Research/ESA U.S. Energy Storage Monitor (March 2018).

[33] SEPA (2018).

Table 3a breaks down the distribution of the 51.4 percent of new capacity developed with contracts. As shown, utility and community choice aggregator (CCA) projects account for 36 percent of all new capacity, or 70 percent of contracted capacity. A CCA is a local government entity that operates within the service area of an investor-owned utility and purchases power on behalf of the residents and businesses of a city or district. All of the CCAs responsible for new capacity in these two years are in California.

Direct contracts with customers account for 12 percent of all capacity or 23 percent of all contracts. These contracts included customers such as Google, Amazon, Kimberly Clark, Whirlpool, as well as hospitals and universities. Such contracts represented seven percent of all capacity in 2015, and three percent in 2014, according to earlier analyses from the American Public Power Association. These contracts are almost entirely for the purchase of wind and solar power.

Two small categories account for the remainder of the contracts:

Financial hedges are arrangements where the project developer or entity financing the project receives a guaranteed price from a third-party financial entity for a quantity of the energy output. If the market price is below the guaranteed price, the hedge provider pays the difference to the project developer. If the market price is higher, the project developer pays the difference to the hedge provider. Project developers seek hedges where they do not find a party to purchase the power through a long-term agreement, and hedges tend to be between 10-13 years, which is shorter than traditional long-term contracts.[34] All of the financial hedges in the past two years were for wind projects in Texas.

Virtual net metering occurs when a solar developer sells their net metering credits to another entity. Because the developer is not an end user of electricity, it does not have a utility bill to offset and cannot benefit from net metering. The purchaser of the credits can then use the credits to reduce their utility bill. For the past two years, most of the virtual net metering arrangements have been for towns in Massachusetts that use the net metering credits to offset the electricity used by the town's buildings and facilities.

Table 3a. Distribution of New Capacity with Contracts, 2016-2017

Type of Contract	Hydro-power	Natural Gas	Nuclear	Solar	Storage	Wind	Other	Total	% of Total capacity
MW of Net Summer Capacity									
Contract with Utility/CCA	7.2	316.4	-	10,208.9	102.6	7,026.8	158.1	**17,820.0**	**35.9%**
Contract with Customer	-	12.8	-	1,331.0	3.0	4,543.0	9.4	**5,899.2**	**11.9%**
Financial Entity Hedge	-	-	-	-	-	1,790.5	-	**1,790.5**	**3.6%**
Virtual Net Metering	-	-	-	60.6	-	-	-	60.6	0.1%
Total	**7.2**	**329.2**	**-**	**11,600.5**	**105.6**	**13,360.3**	**167.5**	**25,570.3**	**51.5%**
Percent of Contracts	0.03%	1.3%	0.0%	45.4%	0.4%	52.2%	0.7%	100%	

34 See for example, "Texas finds wind security in hedges," *Windpower Monthly* (April 30, 2015).

Table 3b. Distribution of New Capacity Owned by Utility or Customer, 2016-2017

Owner	Hydro-power	Natural Gas	Nuclear	Solar	Storage	Wind	Other	Total	% of Total capacity
MW of Net Summer Capacity									
Utility	572.4	10,855.6	1,224.0	1,013.2	116.9	1,128.3	143.5	**15,053.9**	**30.3%**
Customer	7.3	230.4	-	105.5	-	5.5	108.0	**456.7**	**0.9%**
Total	**579.7**	**11,086.0**	**1,224.0**	**1,118.7**	**116.9**	**1,133.8**	**251.5**	**15,510.6**	**31.2%**
Share of Ownership	3.7%	71.5%	7.9%	7.2%	0.8%	7.3%	1.6%	100%	

Table 3b shows the distribution of new capacity constructed under an ownership model, almost all of which was constructed by utilities. Customer-owned generation tends to be smaller and has generally involved solar panels, wind turbines, combined heat and power, or biomass facilities owned by hospitals, colleges, data centers, wastewater treatment plants, factories, and others.

Table 4 shows the distribution of all utility projects, including contracts, ownership, and community solar, according to the type of utility contracting for the power or owning the resource. Utility projects account for 67 percent of all new capacity. As noted previously, utility contracts are dominated by wind and solar, while ownership is comprised primarily of natural gas.

New capacity under contract with or owned by a utility shows a much greater diversity than the merchant projects, with roughly one-third comprised of natural gas, one-third solar, and one-quarter wind. In contrast, new merchant capacity is 86 percent natural gas and 12 percent wind, with a small amount of storage and solar. Hydropower and nuclear power are not present in the merchant projects but represent just under two and four percent of the utility projects, respectively.

Public power accounted for 28 percent of all utility-owned or contracted new capacity, although these utilities provide 15 percent of sales to final customers.[35] Public power also accounted for a significant share of new hydropower (96 percent) and nuclear power (92 percent). It is possible, however, that the capacity of community solar facilities constructed by public power is understated. There are currently 37 public power community solar programs, compared to 160 electric cooperative programs, and 31 IOU programs,[36] but many of the public power programs are likely to be too small to be in the EIA database.

[35] *2017–2018 Annual Directory & Statistical Report*, U.S. Electric Utility Industry Statistics, Sales to Ultimate Consumers, American Public Power Association, at 37.

[36] SEPA (2018).

Table 4. Distribution of New Utility Capacity, 2016-2017

Arrangement	Hydropower	Natural Gas	Nuclear	Solar	Storage	Wind	Other	Total	
MW of Net Summer Capacity									
Utility Contracts									**% of Contracts**
IOU	-	316.4	-	7,023.9	82.0	3,545.9	78.9	11,047.1	62.0%
Public Power	-	-	-	2,515.1	9.6	1,560.5	68.9	4,154.1	23.3%
Coop	3.6	-	-	414.4	11.0	1,796.7	8.3	2,234.0	12.5%
IOU & PP	-	-	-	130.0	-	-	-	130.0	0.7%
State Agency*	3.6	-	-	2.0	-	77.7	-	83.3	0.5%
CCA	-	-	-	123.5	-	46.0	2.0	171.5	1.0%
Total	**7.2**	**316.4**		**10,208.9**	**102.6**	**7,026.8**	**158.1**	**17,820.0**	**100%**
% of Contracts	**0.04%**	**1.8%**		**57.3%**	**0.6%**	**39.4%**	**0.9%**	**100%**	
Utility Ownership									**% of Ownership**
IOU	9.1	6,749.5	102.0	903.9	80.5	450.0	37.3	8,332.3	55.3%
Public Power	556.8	2,819.9	1,122.0	52.4	35.4	676.6	13.2	5,276.3	35.1%
Coop	6.5	1,286.2	-	56.9	1.0	1.7	93.0	1,445.3	9.6%
Total	**572.4**	**10,855.6**	**1,224.0**	**1,013.2**	**116.9**	**1,128.3**	**143.5**	**15,053.9**	**100%**
% of Ownership	**3.8%**	**72.1%**	**8.1%**	**6.7%**	**0.8%**	**7.5%**	**1.0%**	**100%**	
Community Solar									
IOU				328.4				328.4	
Public Power				8.0				8.0	
Coop				35.7				35.7	
Total				**372.1**				**372.1**	
Total Utility									**% of Total Utility**
IOU	9.1	7,065.9	102.0	8,259.0	162.5	3,995.9	116.2	**19,710.6**	**59.3%**
Public Power	556.8	2,819.9	1,122.0	2,572.9	45.0	2,237.1	82.1	**9,435.8**	**28.4%**
Coop	10.1	1,286.2	-	505.7	12.0	1,798.4	101.3	**3,713.7**	**11.2%**
Other**	3.6	-	-	255.5	-	123.7	2.0	**384.8**	**1.1%**
Total Utility	**579.6**	**11,172.0**	**1,224.0**	**11,593.1**	**219.5**	**8,155.1**	**301.6**	**33,244.9**	**100%**
% of Total Utility	**1.7%**	**33.6%**	**3.7%**	**34.9%**	**0.7%**	**24.5%**	**0.9%**	**100%**	

* "State agency" includes the purchase of RECs for resale to load-serving entities by the New York State Energy Research & Development Authority, and the procurement of small-scale renewable energy by VEPP, Inc. on behalf of Vermont utilities.
** Other includes state agency and CCA contracts.

Table 5 shows the capacity developed within the Eastern RTOs. As shown, 70 percent of the new capacity within PJM that came online in 2016 and 2017 was merchant, of which 90 percent was natural gas fired. Other than some storage selling into ISO-NE, there was very little merchant generation developed in ISO-NE or the NYISO in these two years, as well as a small amount of new capacity overall developed in these two RTOs.

Data from the ISO-NE Forward Capacity Auctions (FCAs) corroborates this low level of new capacity. Only 79 MW of new generation cleared FCA #6, procuring capacity for the 2015-2016 delivery year, 800 MW cleared FCA #7 for 2016-2017, and 30 MW cleared FCA #8 for 2017-2018. More than 1,000 MW of new capacity cleared the next two capacity auctions for delivery years 2018-2019 and 2019-2020.[37] One significant source of new merchant capacity, clearing FCA #7, is the 674 MW Footprint Power Salem Harbor natural gas plant, which requested and received a one year deferral of its capacity

Table 5. New Capacity in the Eastern RTOs, 2016-2017

	Hydropower	Natural Gas	Solar	Storage	Wind	Other*	Total	% of RTO Capacity
MW of Net Summer Capacity								
PJM								
Contracts/CS	-	-	560.4	7.0	172.8	9.7	749.9	9.8%
Ownership	44.0	1,402.7	101.8	-	-	6.0	1,554.5	20.4%
Merchant	-	4,778.3	34.7	48.3	462.0	-	5,323.3	69.8%
% of Merchant	-	89.8%	0.7%	0.9%	8.7%	0.0%	**100%**	-
Total	**44.0**	**6,181.0**	**696.9**	**55.3**	**634.8**	**15.7**	**7,627.7**	**100%**
% of PJM	**0.6%**	**81.0%**	**9.1%**	**0.7%**	**8.3%**	**0.2%**	**100%**	
ISO-NE								
Contracts/CS	3.6	12.8	196.3	2.6	412.1	11.3	638.7	89.3%
Ownership	-	2.0	41.6	2.0	-	14.7	60.3	8.4%
Merchant	-	-	-	16.2	-	-	16.2	2.3%
Total	**3.6**	**14.8**	**237.9**	**20.8**	**412.1**	**26.0**	**715.2**	**100%**
% of ISO-NE	**0.5%**	**2.1%**	**33.3%**	**2.9%**	**57.6%**	**3.6%**	**100%**	
NYISO								
Contracts/CS	-	-	63.8	-	77.7	-	141.5	94.5%
Ownership	-	-	3.0	-	-	5.3	8.3	5.5%
Total	-	-	**66.8**	**-**	**77.7**	**5.3**	**149.8**	**100%**
% of NYISO			**44.6%**		**51.9%**	**3.5%**	**100%**	

[37] *Results of the Annual Forward Capacity Auctions*, ISO-NE website.

obligation to delivery year 2017-2018.[38] Footprint Power was able to lock in the capacity price for five years, explaining that, "Five years of capacity market revenues was viewed as the minimum time necessary for lenders to be willing to finance a new merchant project."[39] The plant was completed in May 2018.[40]

New merchant natural gas plants are also under development in the NYISO, but have not yet come online. These plants include the 1,177 MW Cricket Valley Energy Center II, expected to be in service in 2020, and the recently completed 820 MW CPV Valley Energy Center, as well as a number of wind projects, although these are not necessarily merchant.[40, 41]

38 *Application for Deferral of Capacity Supply Obligation*, Footprint Power Salem Harbor Development LP, Federal Energy Regulatory Commission, Docket ER15-60 (October 7, 2014).

39 *Id.* at 11.

40 Table 6.3. New Utility Scale Generating Units by Operating Company, Plant, and Month, Electric Power Monthly (June 2018).

41 *2018 Load and Capacity Data*, Gold Book, New York ISO, Table IV-1, Proposed Generator Additions and CRIS Requests (April 2018).

Assessment of New Merchant Capacity in 2016 and 2017

Table 6 shows the type and location of the new merchant capacity developed in 2016 and 2017, the bulk of which is comprised of natural gas plants and wind farms in PJM and ERCOT.

Most of the merchant generation that began service in this two-year period in PJM is comprised of six natural gas plants: three constructed by Panda Power (the Liberty and Patriot plants in Pennsylvania, and Stonewall in Virginia); the Oregon Clean Energy Center built by CME Energy in Ohio; Advanced Power's Carroll County Energy, also in Ohio; and CPV's St. Charles Energy Center in Maryland.

Another four natural gas plants (Beaver Dam, Alpaca, Milan and Eagle Point) within PJM are small facilities. Eagle Point was developed by Rockland Capital and the other three were built by IMG Midstream, a company that specializes in small natural gas plants located on the distribution or sub-transmission system with access to natural gas from the Marcellus shale.[42]

Table 6. New Merchant Capacity, 2016-2017

Type/Name	State	MW of Net Summer Capacity	Type/Name	State	MW of Net Summer Capacity
Natural Gas			**Wind**		
CPV St Charles Energy Center	MD	726.0	Kelly Creek	IL	184.0
Eagle Point Power	NJ	26.8	Radfords Run	IL	278.0
Carroll County Energy	OH	682.6	Milo	NM	50.0
Oregon Clean Energy Center	OH	849.1	San Roman	TX	95.3
Milan	PA	20.4	Astra	TX	163.0
Alpaca	PA	20.4	Bruenning's Breeze	TX	228.0
Beaver Dam	PA	21.0		**Subtotal Wind**	**998.3**
Panda Liberty	PA	829.0	**Solar**		
Panda Patriot	PA	829.0	CES Cherry Hill	NJ	1.2
Panda Stonewall	VA	774.0	East Amwell	NJ	1.8
Colorado Bend II	TX	1,087.6	Junction Road	NJ	4.4
Wolf Hollow II	TX	1,069.3	Sharon Station	NJ	2.7
Port Comfort Power	TX	86.0	North Bergen	NJ	1.7
Chamon Power	TX	86.0	Delilah Road Landfill	NJ	8.5
	Subtotal Natural Gas	**7,107.2**	Seashore	NJ	8.5
Storage			Cedar Branch	NJ	5.9
Clinton Battery	OH	10.0	North Gainesville	TX	5.2
Green Mountain Storage	PA	10.5		**Subtotal Solar**	**39.9**
Willey Battery	OH	6.0		**Total New Merchant**	**8,249.8**
William F Wyman	ME	16.2			
McHenry	IL	19.8			
NA 1(Hagerstown)	MD	2.0			
Blue Summit Storage	TX	30.0			
Inadale Wind Farm	TX	9.9			
	Subtotal Storage	**104.4**			

[42] "IMG Midstream Does Enviro Friendly Tiny Power Plants," *Natural Gas Now*, April 10, 2017; IMG Midstream web site.

The two key motivators identified by developers of merchant natural gas plants in PJM are the availability of low-cost natural gas and projected retirements of coal plants.[43] CPV St. Charles Energy Center, however, was not initially developed as a merchant plant. The impetus for this plant was its selection for a long-term contract under a Maryland Public Service Commission solicitation.[44] As with the Newark and Woodbridge plants in New Jersey, this contract was invalidated by the Supreme Court's decision in Hughes v. Talen.

Natural gas plant construction in Texas in 2016 and 2017 was primarily comprised of two large plants, Wolf Hollow II and Colorado Bend II.[45]

Six merchant wind projects were also constructed in 2016 and 2017, two in the PJM portion of Illinois, three in Texas, and one smaller 50 MW wind farm in New Mexico that was constructed for sale into the SPP real-time market.[46] While merchant wind capacity has grown in recent years, a 2017 report from the Brattle Group noted that such "merchant projects are exposed to significant market risk as they need to absorb price fluctuations and anticipate how their own production outputs may or may not vary favorably in relation to market tightness. This risk can create a barrier for initial financing and can impact the economic feasibility of the projects."[47]

While the expansion of merchant power shows that the RTO-operated capacity and energy markets can attract new generation development, despite the price volatility in these markets, there are several reasons to question whether this is a positive development and one that FERC and the market operators should seek to promote. Several factors to consider regarding merchant generation are:

- These plants all use a variety of equity financing and Term Loan B debt, incurring a higher cost of capital than traditional debt.[48]

- Merchant development does not involve long-term planning to determine if the development of such a large amount of natural gas within one region will be beneficial, and whether it will exacerbate the RTOs' increasing concerns about fuel security.

- The capacity market is procuring excess capacity in PJM, yet merchant development is increasing, indicating a disconnect between reliability needs and new capacity development.[49]

- It is not known if the expected earnings of the merchant developers fully account for the other merchant projects and their impact on each individual developer's projections of natural gas, energy, and capacity prices. If the increased merchant natural gas development causes natural gas prices to rise or energy prices to remain low, then the

[43] Panda Power states that the "very large need for generation is driven by": coal plant retirements, enormous natural gas reserves, an aging generating fleet, growing renewable generation and regulatory uncertainty that could impact nuclear, coal and older natural gas plants. Panda Power Funds website, visited May 27, 2018.

[44] "Maryland PSC Orders New Natural Gas Generation," Maryland Public Service Commission Press Release (April 12, 2012).

[45] Exelon Reports Third Quarter 2017 Results, News Release, November 2, 2017.

[46] "EDF Renewables and BlackRock Close on the Sale in Two Wind Projects in New Mexico," EDF Renewables Press Release (March 14, 2016).

[47] *Managing Price Risk for Merchant Renewable Investments: Role of Market Interactions and Dynamics on Effective Hedging Strategies*, The Brattle Group (January 2017) at 20.

[48] For example, a report from the ISO/RTO Council explains that "Term Loan B typically sits equal to Term Loan A on a security basis, but has fewer restrictive covenants –e.g. 50% vs. 100% hedging requirements –and requires nil or minimal amortization. These eased restrictions imply a greater risk, and thus higher interest rates, compared to Term Loan A. *Resource Investment in the Golden Age of Energy Finance: Financial Investment Drivers and Deterrents in the Competitive Electricity Markets of the US and Canada*, ISO/RTO Council and Market Reform (May 2015), at 13.

[49] For example, the amount by which the capacity exceeded the reserve margin was 8,209 MW as of June 1, 2016, and 10,522 MW as of June 1, 2017 and is expected to be 17,590 MW or 12.6 percent by June 1 of 2018. Table 5-7, RPM reserve margin: June 1, 2016 to June 1, 2020. 2017 *State of the Market Report for PJM*, Monitoring Analytics, March 8, 2018, at 249.

projected earnings would not materialize.[50] If that occurs, will the plant owners close the plants, or will they instead seek market rule changes to preserve these plants?

- The growth in merchant natural gas plants may not necessarily be matched by an expansion of natural gas pipeline capacity due to the general unwillingness of merchant natural gas plants to arrange for firm pipeline capacity. Both PJM and ISO-NE have tried unsuccessfully to incent such contracting through market-rule changes.[51]

An often-stated fundamental benefit of the merchant model is that the risk is shifted away from consumers and on to the investors in the plant.[52] But the history of the development of buyer-side mitigation in the Eastern RTOs demonstrates an unwillingness of merchant owners to accept the risks of competing supply. Another example of an unwillingness to accept risks is the lawsuit bought by Panda Power against ERCOT after its Temple 1 power plant declared bankruptcy. Panda Power claimed that ERCOT changed its forecasting methodology and shifted the market outlook from undersupply to oversupply, resulting in depressed prices and the inability of Panda to lock in a hedge for the output of the plant.[53]

In sum, an increasing reliance on merchant generation may be at odds with the growing interest in developing specific capacity types to meet local, state, and even FERC policy goals, whether they are environmental, local reliability, fuel diversity, or grid resilience. Moreover, policies put in place to protect prices increase consumer costs and detract from the claimed benefit that the merchant generation model shifts risks away from consumers.

[50] A recent white paper by Wilkinson, Barker, Knauer and the Power Research Group explains that "the price forecasts underpinning investments in competitive generation assets tend to be made during the period of scarce supply and rising prices, when investment opportunities look attractive. The prices that prevail once these investments come on line, by contrast, tend to reflect growing over-supply and the erosion of prices down to variable cost. The irony of this pattern of decision making is that investors rightly require higher expected returns, often in the mid to high teens, to compensate for the risk of investing in a highly cyclical industry. When the conditions materialize that might allow investors to achieve these returns, the flow of capital into the industry, and the oversupplied conditions that follow, render such returns permanently unattainable." *The Breakdown of the Merchant Generation Business Model*, by Raymond L. Gifford, Robin J. Lunt, and Matthew S. Larson, Wilkinson, Barker, Knauer, and Hugh Wynne and Eric Selmon, Power Research Group (June 2017) at 2.

[51] For example, PJM has stated that it "was hoping that Capacity Performance changes would spur a corresponding array of new service offerings by pipelines (and generators seeking such options), at least on the public record such new pipeline services have not been offered as new open season requests (with the notable exception of the Texas Eastern open season)." *Response of PJM Interconnection, LLC*, Docket AD18-7, Federal Energy Regulatory Commission (March 9, 2018) at 57-58. ISO-NE President & CEO Gordon van Welie has stated that: "The ISO assumed fuel-security challenges could be addressed by improving performance incentives for generators and that additional fuel infrastructure would be built (e.g., dual fueling); however, investment in adequate fuel infrastructure has stalled." *ISO New England Presentation to House Members of Massachusetts Joint Committee on Telecommunications, Utilities and Energy*, Slide 15 (May 23, 2018).

[52] For example, PJM claims that: "Under the merchant model, the financial and operational risks associated with this generation are shifted from customers to the investors in those plants." PJM Interconnection, Capacity Reprising Proposal (April 9, 2018) at 3.

[53] "Panda Temple bankruptcy could chill new gas plant buildout in ERCOT market," *Utility Dive*, May 15, 2017.

Conclusions and Recommendations

Merchant development of new capacity has been increasing, although almost entirely within PJM and ERCOT. Accompanying this expansion of merchant capacity has been the growth in state efforts to procure or retain specific types of capacity, and a recognition by the RTOs that a heavy reliance on natural gas can create fuel security and resilience concerns. Yet these state and RTO policy concerns are not embedded in the earnings goals of the merchant generators, and the vast majority of merchant development has been a single fuel. It is not clear how sustainable the merchant model will be should natural gas prices rise or projected electricity price increases fail to materialize.

Despite the shortcomings of the merchant model, the Eastern RTOs have sought to protect the prices earned by the merchant generators by deeming merchant resources to be "in-market" and vertically integrated or state-sponsored resources to be "out-of-market." The American Public Power Association has long argued for a removal of such artificial distinctions and the accompanying buyer-side mitigation rules. Instead, as is done in much of the country, the primary means of capacity procurement should be bilateral contracting or ownership, whether by utilities or end users themselves. Within the restructured states, state actions to procure new resources or retain existing resources should be permitted without buyer-side mitigation rules that can impose additional costs on consumers.

APPENDIX

Financial Arrangements Behind 2016 New Capacity
(MW of Net Summer Capacity)

Type of Arrangement	Hydro-power	Natural Gas	Nuclear	Solar	Storage	Wind	Other	Total	% of Total
Contracts									
Contract with Utility/CCA	4.8	316.4	-	7,130.5	70.8	4,402.9	53.0	11,978.4	42.2%
Contract with Customer	-	-	-	561.3	-	2,949.6	9.4	3,520.3	12.4%
Financial Entity Hedge	-	-	-	-	-	690.4	-	690.4	2.4%
Virtual Net Metering	-	-	-	25.8	-	-	-	25.8	0.1%
Subtotal Contracts	**4.8**	**316.4**	-	**7,717.6**	**70.8**	**8,042.9**	**62.4**	**16,214.9**	**57.1%**
Percent of Contracts	0.03%	2.0%	-	47.6%	0.4%	49.6%	0.4%	100%	
Ownership									
Utility Ownership	374.5	7,029.8	1,122.0	468.8	59.0	678.3	117.0	9,849.4	34.8%
Customer Ownership	-	104.3	-	30.3	-	1.7	10.7	147.0	0.5%
Subtotal Ownership	**374.5**	**7,134.1**	**1,122.0**	**499.1**	**59.0**	**680.0**	**127.7**	**9,996.4**	**35.3%**
Percent of Ownership	3.7%	71.4%	11.2%	5.0%	0.6%	6.8%	1.3%	100%	
Community Solar				**107.5**				**107.5**	**0.4%**
Merchant	-	**1,705.8**	-	**34.7**	**62.5**	**234.0**	**-**	**2,037.0**	**7.2%**
Percent of Merchant	-	83.7%	-	1.7%	3.1%	11.5%	-	100%	
Total	**379.3**	**9,156.3**	**1,122.0**	**8,358.9**	**192.3**	**8,956.9**	**190.1**	**28,355.8**	
% of Total	**1.3%**	**32.3%**	**4.0%**	**29.5%**	**0.7%**	**31.6%**	**0.6%**	**100%**	

Financial Arrangements Behind 2017 New Capacity

(MW of Net Summer Capacity)

Type of Arrangement	Hydro-power	Natural Gas	Nuclear	Solar	Storage	Wind	Other	Total	% of Total
Contracts									
Contract with Utility/CCA	2.4	-	-	3,078.4	31.8	2,623.9	105.1	5,841.6	27.4%
Contract with Customer	-	12.8	-	769.7	3.0	1,593.4	-	2,378.9	11.1%
Financial Entity Hedge	-	-	-	-	-	1,100.1	-	1,100.1	5.1%
Virtual Net Metering	-	-	-	34.8	-	-	-	34.8	0.2%
Subtotal Contracts	**2.4**	**12.8**	**-**	**3,882.9**	**34.8**	**5,317.4**	**105.1**	**9,355.4**	**43.8%**
Percent of Contracts	0.03%	0.1%		41.5%	0.4%	56.8%	1.1%	100%	
Ownership									
Utility Ownership	197.9	3,825.8	102.0	544.4	57.9	450.0	26.5	5,204.5	24.4%
Customer Ownership	7.3	126.1	-	75.2	-	3.8	97.3	309.7	1.5%
Subtotal Ownership	**205.2**	**3,951.9**	**102.0**	**619.6**	**57.9**	**453.8**	**123.8**	**5,514.2**	**25.9%**
Percent of Ownership	3.7%	71.7%	1.9%	11.2%	1.1%	8.2%	2.2%	100%	
Community Solar				**264.6**				**264.6**	1.2%
Merchant	**-**	**5,401.4**	**-**	**5.2**	**41.9**	**764.3**	**-**	**6,212.8**	**29.1%**
Percent of Merchant	-	86.9%	-	0.1%	0.7%	12.3%	-	100%	
Total	**207.6**	**9,366.1**	**102.0**	**4,772.3**	**134.6**	**6,535.5**	**228.9**	**21,347.0**	
% of Total	**1.0%**	**43.9%**	**0.5%**	**22.3%**	**0.6%**	**30.6%**	**1.1%**	**100%**	