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ENERGY VENTURES ANALYSIS

Impact of Coal Plant Retirements on the U.S. Power Markets – PJM Interconnection Case Study

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Executive Summary

Coal-fired power plants have been retiring at a rapid pace in recent years, especially in merchant power markets. The National Mining Association (NMA) commissioned this report by Energy Ventures Analysis, Inc. (EVA) to assess the impact of coal plant closures on the U.S. power markets, including the cost of retiring existing coal-fired baseload units and replacing them with combined cycle gas turbines. While this is a national issue, this case study focuses on the potential retirement of three large coal plants in the PJM Interconnection[1] which is the largest merchant power market in the U.S. PJM is home to about 56,000 MW of coal capacity, which is over 20 percent of the entire U.S. coal fleet.

Three of the largest coal-fired generating stations in PJM are at risk of closure in the near term (Pleasants, Sammis, and Bruce Mansfield), which total 5,258 MW, almost 10 percent of the total PJM coal fleet.[2] EVA used the potential closure of these plants to analyze the impact of closing coal-fired plants on the merchant power markets. This study reached the following conclusions:

- EVA analyzed the likely impact on power market prices in PJM (energy and capacity markets) if the three coal plants were to retire at the beginning of 2019. We found that **the cost of power in the PJM market would increase by $2.0** billion annually due to increased energy and capacity market prices. These increased costs would be passed on to retail customers.
- We estimate that the additional cost to support the three coal plants would total about $130 million above the revenues these plants are likely to receive in the power markets. The cost to support these plants would be **less than 10 percent of the increased cost** to the PJM market customers if these plants were to close.
- To provide the PJM power market with the same amount of capacity and energy, merchant power generators would need to replace the three coal plants with 5,258 MW of gas-fired Combined Cycle Gas Turbines (CCGT) plants.[3] **The capital cost to replace these coal plants with the same amount of new CCGT capacity would be $5.7 billion**. It is highly unlikely that merchant power producers would invest this capital without significantly higher power prices.

Annual Cost of Generation in PJM from Closing Three Coal Plants

$million

Value of Preserving The Coal Plants	**Energy**	**Capacity**	**Total**
Increased power cost from closing	$ 1,393	$ 657	$ 2,050
Cost to support the coal plants		$ (130)	$ (130)
Net savings from keeping the coal plants	**$ 1,393**	**$ 527**	**$ 1,920**
Capital cost to build new CCGT gas plants		$ 5,700	

- Merchant power markets like PJM are not structured to compensate coal plants for the reliability and resilience that they provide to the market. The demand for electricity fluctuates regularly by the time of day, the day of the week and season. The market needs coal plants to be available during periods of high demand, but they are forced to operate at a loss during off-peak periods when they are turned down to minimum load, in order to be available to supply power during peak periods. This is in contrast to natural gas plants, which can economically turn off during

[1] The PJM Interconnection, originally covering most of the states of Pennsylvania, New Jersey, Maryland and Delaware, has expanded to include power generation across much of Ohio, Kentucky and Illinois. PJM is an independent system operator and manages the dispatch of power plants across this entire region so that generation matches load on a real-time basis. Some of the power plants in PJM are owned by regulated electric utilities and receive cost-of-service recovery in their retail rates, but most of the generators in PJM are merchant power plant which receive compensation for energy sales and capacity commitments at market prices established by PJM.

[2] A list of the PJM coal plants which have been closed since the Polar Vortex event in January 2014 and have announced plans to close through 2020 is shown in Appendix A.

[3] The total amount of wind and solar capacity in PJM is just 1,700 MW. Replacing the three coal plants with new wind plants would require almost 30,000 MW of wind turbines at a capital cost of $59 billion to provide the same amount of peak capacity.

periods of low demand and low prices, and subsidized renewable plants (wind and solar), which have negligible operating costs (thus not forced to operate at a loss).

- However, coal plants are the primary source of resilience for the power market – the ability to generate increased power when needed by the system operator to meet demand. Wind and solar cannot increase generation as they already run as hard as possible when available. Nuclear plants provide reliability but because they are typically operated at maximum levels when the plant is available, their contributions to resilience – or their ability to increase generation when needed – are minimal. Natural gas plants provide resilience, as they can readily follow load, **except in periods of extreme cold weather,** when both home heating demand and power demand are at a peak at the same time, and gas cannot be delivered in sufficient quantities to support both markets. In these peak periods, coal is the only source of resilience for the power system.
- The coal fleet demonstrated its value during the most recent periods of extreme cold weather – the "Bomb Cyclone" of January 2018 and the "Polar Vortex" of January – February 2014. In these periods of high demand, coal plants provided most of the increased supply of power needed by the market, as increased gas supply for power generation was not available. Half of the total PJM natural gas capacity was not available to supply peak demand on January 7, 2018.

Introduction

There has been a surge of announced retirements of coal-fired power plants across the United States in 2017 and 2018. There are several factors driving these decisions, including the low demand growth for electricity, the displacement of coal generation by heavily subsidized wind and solar power, increased generation from natural gas, and the continuing cost of recent environmental regulations on coal plants.[4] Coal plant retirements in 2018 will total almost 15,000 MW, about 6 percent of the total national coal fleet.

Merchant Power Markets do not Consider All Impacts of Plant Retirements

There is a fundamental difference between traditionally regulated utility power systems and merchant generation in a wholesale power market. When utilities make long-term decisions about power supply resources (such as retiring coal plants), the utility and the state regulatory commission consider all the effects on the power system, including reliability, system diversity, environmental issues, and minimizing long-term power costs to ratepayers. In a merchant power market, the plant owner has no obligation to consider any factors other than the economics of its power plants and will maximize profitability in compliance with applicable regulations.

In a merchant power market, the independent system operator manages the supply of power to meet demand. The largest merchant power market in the United States is the PJM Interconnection. PJM manages a market for both capacity (which pays power suppliers for having capacity available to meet demand) and energy (which pays power suppliers for each kWh which they generate). The total cost of the demand and energy charges are spread across all the retail power providers in PJM (including regulated utilities).

When a merchant power producer decides to retire a coal-fired power plant, doing so will have significant impacts on the power system. The amount of available generating capacity will be reduced, which will reduce the reserve margins and increase the market price for generating capacity. Also, the marginal price of electric generation will be higher, increasing the average energy costs across the system. Further, the loss of coal capacity will reduce the system reliability and resilience to respond to the demand for electricity.

Regional transmission organizations (RTO) like PJM rely on the market to provide the lowest-cost power over time. However, the market structure and significant government interventions in the market (federal subsidies in the form of tax credits for wind and solar power and state laws which designate market shares through renewable portfolio mandates) have created a system that penalizes unsubsidized coal plants, because of their higher fixed costs, while not rewarding the value of their reliability, resilience and fuel security attributes.

Impact of Potential Coal Plant Retirements on PJM Power Costs

Coal-fired power plants provide a large share of the capacity and power generation in PJM. As of February 1, 2018, the installed net dependable capacity (ICAP) of coal plants in PJM totaled 56,191 MW, 31.5 percent of the total capacity of 178,146 MW.[5] The merchant coal fleet in PJM totaled 34,569 MW as the remaining coal plants were owned or contracted by regulated utilities.

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[4] For the Mercury and Air Toxics (MATS) rule, EPA estimated that the annual cost of compliance would be $9.6 billion, primarily from constructing new scrubbers on coal-fired plants to remove acid gases (hydrogen chloride). EPA could only quantify $4 to $6 million in benefits associated with the reduction in mercury emissions (and zero quantified benefits from reducing acid gas emissions) but justified the cost-benefit analysis based on co-benefits from reduced emissions of sulfur dioxide (not regulated directly by MATS but removed in the process of scrubbing for acid gases) equal to $37 - $90 billion annually. See Federal Register Volume 80, No. 230 at 75041.

[5] PJM Interconnection, 2021-2022 rpm resource model at http://www.pjm.com/markets-and-operations/rpm.aspx.

Three of the largest merchant coal-fired power plants operating in PJM are at risk of retirement due to the low energy and capacity market prices caused by the impact of subsidies and mandates:

TABLE 1: LARGE MERCHANT COAL PLANTS AT RISK OF RETIREMENT[6]

Plant	Units	Years Built	State	Capacity	2017 Generation	Capacity Factor	Coal Burn
				MW	*GWh*	*%*	*'000 tons*
Bruce Mansfield	1-3	1976 - 1980	PA	2,490	7,686	35.2	3,305
Sammis*	5-7	1967 - 1971	OH	1,278	6,180	55.2	2,739
Pleasants	1-2	1979 - 1980	WV	1,490	7,808	59.8	3,172
Total				**5,258**	**21,674**	**47.1**	**9,216**

** Excludes older Sammis units 1-4 (640 MW) which were previously scheduled to retire on May 31, 2020.*

These three plants at risk of retirement represent almost 10 percent of the total coal-fired capacity in PJM and over 15 percent of the merchant coal capacity. This paper provides an analysis of the projected impact of closing these plants on the market price for energy and capacity in PJM. In performing this analysis, EVA used its power market model to project the PJM market prices for energy and capacity for the 10-year period 2019 – 2028, with and without these merchant coal plants.

Impact of Closing the Coal Plants on PJM Energy Costs

EVA projected the energy market price for PJM for the period 2019 – 2028 using a power dispatch model, which solves for the marginal cost of generation for every hour of the year. In this analysis, EVA used the following inputs from independent third-party sources:

- PJM's forecast of energy demand and generation[7]
- EIA's forecast of natural gas prices[8]

EVA modeled the PJM energy prices under two scenarios:

- Assuming the three coal-fired plants continued to operate for the entire 10-year period
- Assuming the three coal-fired plants retire effective January 1, 2019

The forecast results show that the expected increase in the average PJM energy market price would be $1.70 per MWh if the three coal plants closed early compared to the scenario where they continued to operate over the entire period. Based on average market demand of 819 TWh for PJM over the next 10 years, the average annual cost to the PJM retail electric power ratepayers would be $1.393 billion, or $13.9 billion over the 10-year period.

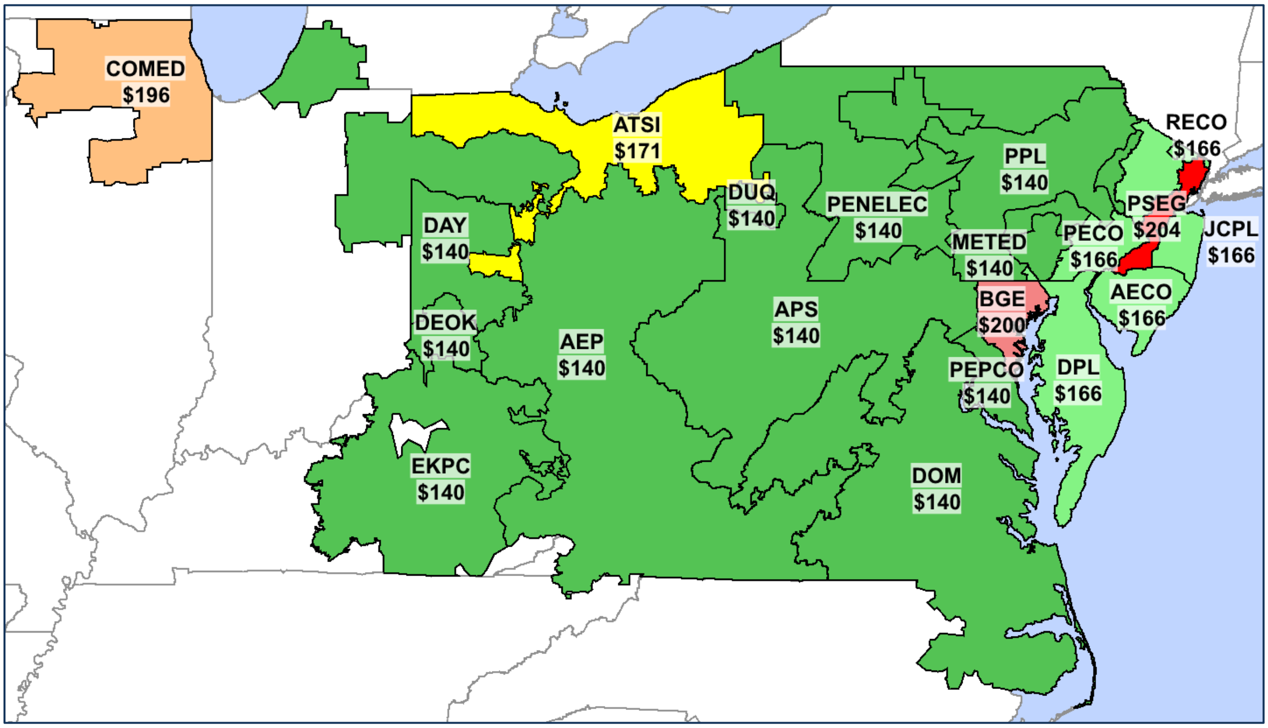
Impact of Closing the Coal Plants on PJM Capacity Costs

PJM has a separate market to procure generating capacity to provide a reliable supply of power to meet peak demand with a reserve margin in accordance with PJM's reliability standards. PJM procures capacity under its Base Residual Auction (BRA) three years ahead of the power delivery year, to provide new resources with the time to enter the market.

[6] Installed capacity (ICAP) from PJM; 2017 generation and burn from EIA Form 923.
[7] PJM Interconnection.
[8] US Energy Information Administration, Annual Energy Outlook 2018.

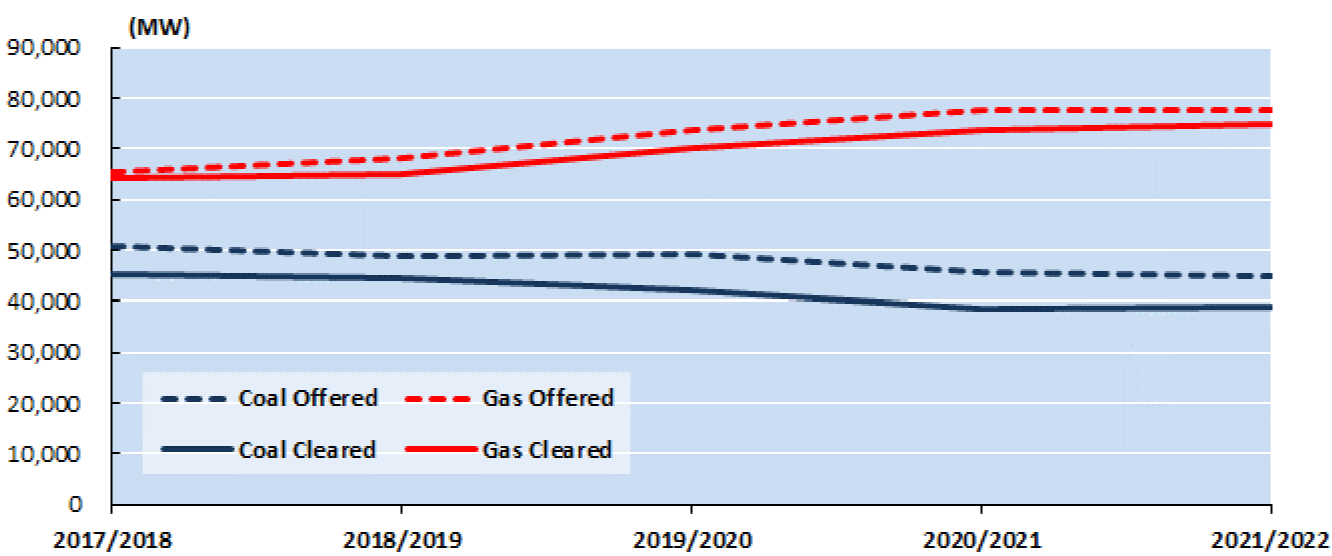
PJM's latest capacity auction was in May 2018 for capacity committed for the 12-month period June 2021 – May 2022 (2021/2022 BRA).

TABLE 2: MAY 2018 RESULTS OF 2021/22 PJM BASE RESIDUAL AUCTION



The capacity price in the BRA auction is set by the clearing price which contracts for sufficient capacity to meet PJM's load and reserve margin, both for the RTO and for individual zones within PJM. If the amount of capacity offered declines and the prices offered increase, the market clearing price will rise, increasing the cost to all PJM retail ratepayers to pay for reliable capacity. Over the last five years, the amount of coal capacity offered and cleared has declined by 14 percent, while the natural gas capacity offered and cleared has increased by 17 percent.

TABLE 3: PJM BASE RESIDUAL AUCTION CAPACITY OFFERED AND CLEARED – COAL AND NATURAL GAS (MW)



Source: PJM Interconnection

The declining amount of coal capacity clearing the BRA each year shows that the capacity clearing price is not sufficient for coal plants to continue operating with off-peak power prices below their dispatch costs (as opposed to natural gas, where almost all the capacity cleared). To remain economic, the coal plants will require capacity payments sufficient to cover their fixed operating and maintenance (O&M) costs.

The change in the markets, including lower energy market prices and declining coal and nuclear resources, has caused the PJM capacity price to increase significantly in the recent BRA auction. The capacity price for the RTO almost doubled, from $76.53 to $140.00 per MW-day of capacity. The total cost increase across PJM for purchasing capacity increased by over $2.4 billion for the year 2021/2022 compared to the prior year.

TABLE 4: COST INCREASE IN THE MAY 2018 PJM BASE RESIDUAL AUCTION[9]

LDA Zone	Capacity Price 2019/20	Capacity Price 2020/21	Capacity Price 2021/22	Resources Cleared	Cost Increase in 2021/22 BRA From 2019/20	Cost Increase in 2021/22 BRA From 2020/21
	$/MW-day			MW	$Million	
RTO	$ 100.00	$ 76.53	$ 140.00	61,526	$ 898.3	$ 1,425.3
MAAC	$ 100.00	$ 86.04	$ 140.00	16,738	$ 244.4	$ 329.7
EMAAC	$ 119.77	$ 187.87	$ 165.73	22,247	$ 373.2	$ (179.8)
SWMAAC	$ 100.00	$ 86.04	$ 140.00	2,220	$ 32.4	$ 43.7
PS	$ 119.77	$ 187.87	$ 204.29	2,234	$ 68.9	$ 13.4
PS NORTH	$ 119.77	$ 187.87	$ 204.29	3,133	$ 96.7	$ 18.8
DPL SOUTH	$ 119.77	$ 187.87	$ 165.73	1,674	$ 28.1	$ (13.5)
PEPCO	$ 100.00	$ 86.04	$ 140.00	5,949	$ 86.9	$ 117.2
ATSI	$ 100.00	$ 76.53	$ 171.33	6,759	$ 176.0	$ 233.9
ATSI-CLEVELAND	$ 100.00	$ 76.53	$ 171.33	1,248	$ 32.5	$ 43.2
COMED	$ 202.77	$ 188.12	$ 195.55	22,358	$ (58.9)	$ 60.6
BGE	$ 100.30	$ 86.04	$ 200.30	1,938	$ 70.7	$ 80.8
PL	$ 100.00	$ 86.04	$ 140.00	11,233	$ 164.0	$ 221.2
DAYTON*	*$ 100.00*	$ 76.53	$ 140.00	1,637	$ 23.9	$ 37.9
DEOK*	*$ 100.00*	$ 130.00	$ 140.00	2,733	$ 39.9	$ 10.0
Total	**$ 117.58**	**$ 114.81**	**$ 155.71**	**163,627**	**$ 2,276.9**	**$ 2,442.4**

*Dayton and Duke Ohio/Kentucky did not break out as separate Locational Deliverability Areas in the 2019/20 BRA.

The continued decline in coal capacity would further increase the average capacity market price for all PJM retail ratepayers in future years. EVA has modeled the impact of retiring the three coal plants on the future price of the PJM capacity auction. Our model projects that the capacity price would increase by an average of $20.00 per MW-day across all of PJM. After considering the impact of increased energy prices, the net increase in capacity prices would need to be about $11.00 per MW-day to acquire adequate capacity to meet PJM's demand. This would increase average retail power prices by $657 million annually, or $0.81 per MWh.

Total Cost Impact of Closing the Coal Plants on PJM Power Costs

The closing of 5,258 MW of coal capacity in 2019 would increase the total energy and capacity costs across PJM by about $2.51 per MWh average over the next 10 years. The annual cost increase would be over $2.0 billion and would be passed through to PJM ratepayers. This includes increased average annual energy prices equal to $1.39 billion and increased

[9] PJM, 2021-2022 base residual auction results.

average annual capacity costs of $0.66 billion. These costs will increase retail electricity prices paid by ratepayers in the wholesale power cost component of their monthly bill.

Cost of Maintaining the Coal Plants

Coal-fired power plants have higher fixed O&M and maintenance capital costs than gas-fired plants and thus require higher capacity prices to maintain long-term operations. While the costs to operate and maintain these coal plants are not available, the cost for similar utility-owned coal plants can be determined from the utility FERC Form 1 filings.

TABLE 5: 2017 OPERATING COSTS FOR PJM COAL PLANTS[10]

Company	Plant	State	Type	Year Built	Capacity	Generation	Capacity Factor	Fuel Cost	Non-Fuel Production Cost
					MW	*MWh*	*%*	*$/MWh*	*$/MW-day*
Monongahela Power	Fort Martin	WV	Coal	1968	1,098	6,266,279	65.1	$ 25.71	$ 102.73
Monongahela Power	Harrison	WV	Coal	1974	1,954	13,043,034	76.2	$ 25.16	$ 81.65
Appalachian Power	Amos	WV	Coal	1973	2,930	13,892,341	54.1	$ 23.49	$ 94.53
Appalachian Power	Mountaineer	WV	Coal	1980	1,305	7,147,242	62.5	$ 20.80	$ 132.60
Virginia Power	Mount Storm	WV	Coal	1973	1,629	6,997,538	49.0	$ 28.67	$ 117.83
Dayton P&L	Miami Fort*	OH	Coal	1978	368	1,788,065	55.5	$ 22.07	$ 105.72
Dayton P&L	Stuart*	OH	Coal	1974	808	1,790,896	25.3	$ 20.68	$ 89.94
Dayton P&L	Killen*	OH	Coal	1982	402	2,063,089	58.6	$ 18.90	$ 110.06
Dayton P&L	Zimmer*	OH	Coal	1991	371	1,668,070	51.3	$ 20.60	$ 114.59

*Source: FERC Form 1 2017; *Ownership Share*

In addition to the non-fuel O&M costs, which range from $80 to $130 per MW-day, coal plants have annual maintenance capital costs to maintain long-term operations. Based on a prior analysis of FERC Form 1 data, EVA estimates that the annual maintenance capital cost is typically $35 - $50 per MW-day (excluding major new environmental projects). Thus, the total capacity revenues needed to maintain coal plant operations is $105 - $180 per MW-day. However, the PJM capacity revenues are only applicable to the “unforced” capacity (UCAP), which is the summer net capacity reduced by the equivalent forced outage rate (EFORd). Typical forced outage rates for coal plants are 85 - 90 percent of net capacity. Thus, a coal plant will require PJM capacity market revenues equal to $120 - $205 per MW-day.

PJM capacity revenues for these plants will be $100 per MW-day for the period June 2019 – May 2020, $76.53 per MW-day for the period June 2020 – May 2021 and $140 per MW-day for the period June 2021 – May 2022. As only 87 percent of PJM coal capacity cleared at these prices in the recent 2018 BRA auction, it confirms that higher capacity prices would be required to maintain the PJM coal capacity.

Using a target of $160 per MW-day at total net capacity of 5,258 MW, the three coal plants would require annual capacity revenues equal to $307 million. Assuming EFOR of 12.5 percent for the three coal plants, the annual capacity revenues at the PJM BRA prices will be $128.5 million, $168 million, and $235 million for the next three years. The three coal plants would require additional revenues beyond the PJM market equal to about $389.5 million, or $130 million annually.

The annual cost to support the three-coal plant to avoid retirement would be less than 10 percent of the $2.0 billion annual cost to the PJM ratepayers if these plants were to retire.

[10] Source: FERC Form 1 filings

Coal Plants Provide Resilience and Fuel Security

System resilience is provided by generating capacity which can respond to changes in demand for electricity as required by the independent system operator to balance the supply and demand of electricity. The only sources of generation which provide this resilience (or flexibility of generation) are fossil-fuel plants (coal, natural gas, and oil).

Demand for electricity varies widely by time of day (much lower overnight), day of the week (lower over the weekend), and season (high in the summer and winter). Because there is minimal storage capability for electricity, system operators must dispatch the available power plants in real time to match the demand for electricity. Power generation from wind and solar is essentially non-dispatchable – these plants generate power whenever they are available to run. It is the fossil-fueled plants (coal, natural gas and oil) which are dispatched by the system operators to balance supply and demand.

Wind and solar plants provide neither resilience nor reliability. These plants depend upon the availability of the natural resource to generate power. When the wind is not blowing, or the sun is not shining, these plants do not provide generation. Wind is generally inversely correlated with demand for electricity; the wind speed is lower on hot summer afternoons. Wind and solar plants cannot increase generation on demand by a system operator to balance load or replace generator outages.

Nuclear power plants have a high degree of reliability and fuel security with on-site fuel storage. Because of their low fuel costs, nuclear plants are almost always operated at their maximum output when available to operate. As a result, they do not provide the system operator with the ability to increase generation in response to increased load or to replace capacity lost when other plants incur forced outages.

Coal plants can be turned down to their minimum generation (typically 30 - 50 percent of maximum generation) and turned back up to maximum on a regular basis. Many coal plants are ramped up and down daily by system operators to balance the system. Natural gas plants, including both CCGT and combustion turbines (CT), can be turned up and down rapidly to follow load.

Coal plants provide fuel security and fuel diversity. Coal provides fuel security by maintaining on-site fuel storage. Coal plants typically maintain more than 50 days of average burn on site, which provides reliability in case of fuel supply interruptions (including transportation, such as frozen rivers or railroad congestion, and production, or events of high demand).

In contrast, natural gas plants do not have onsite fuel storage (although some plants have limited on-site oil storage as backup fuel). Increasingly, natural gas plants rely upon firm gas transportation contracts with pipelines to provide reliability of fuel supply. PJM considers a firm pipeline contract as adequate to qualify for the Capacity Performance product in the BRA. However, a firm transportation contract does not provide the same degree of reliability as on-site fuel storage. Gas plants with firm transportation contracts are still subject to gas supply interruption during extreme cold weather events, when other customers (residential and commercial) have high demand, reducing the ability of the pipeline to provide service. PJM found that 23 percent of the total generator outages during the 2014 Polar Vortex (9,300 MW) were due to interruptions of natural gas supply.[11]

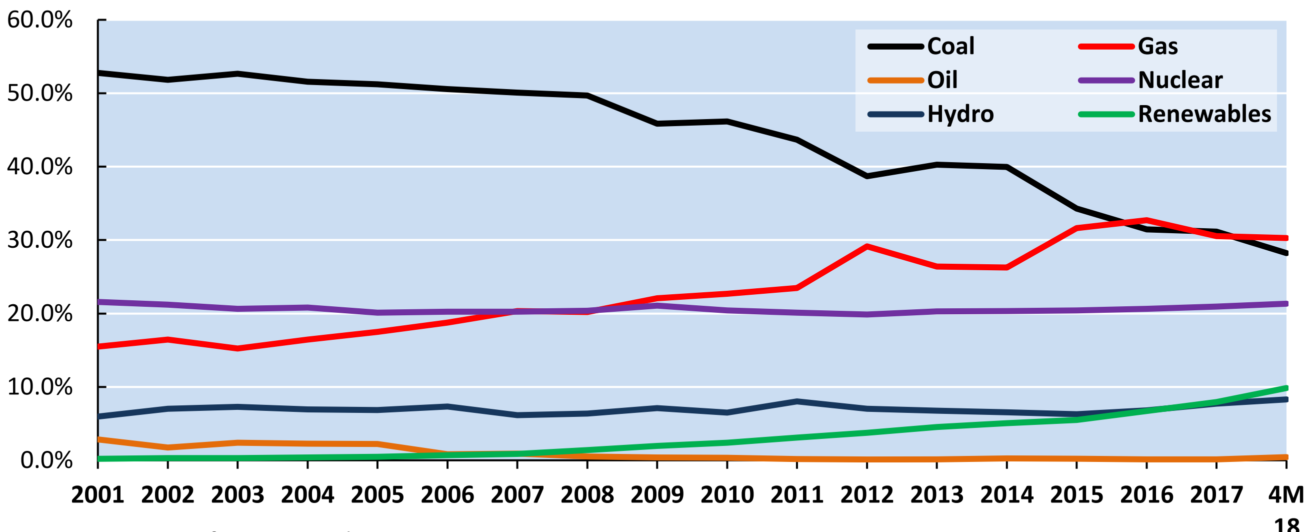
Increasing Reliance on Gas and Renewables is Jeopardizing Reliability

The trend across the country is unmistakable – power supply is shifting rapidly from coal to a combination of natural gas and subsidized renewable (wind and solar) power. Over the last 10 years, the share of total U.S. power generation from

[11] PJM Interconnection, "Strengthening Reliability: An Analysis of Capacity Performance", June 20, 2018.

coal has fallen from 50 percent in 2008 to just 28 percent in the first four months of 2018, replaced by natural gas (whose share is up from 20 percent to 30 percent) and non-hydro renewables (up from 1 percent to 10 percent).

TABLE 6: SHARE OF US POWER GENERATION BY FUEL TYPE[12]



Source: Energy Information Administration

The shift away from coal to gas and renewables is even more pronounced in some regional power markets. In 2017, natural gas accounted for 49 percent of the generation in ISO New England (excluding imports), while coal supplied only 2 percent. In the New York ISO, natural gas provided 36 percent of total generation, while coal was less than 1 percent. In the Florida Regional Coordinating Council, natural gas provided 67 percent of generation in 2017, while coal was only 16 percent. With many announced coal retirements and the addition of new gas units, the share of generation provided by natural gas in Florida will exceed 75 percent by 2020. In all three regions, wind and solar power were only 1 percent of generation, with most of the non-gas power provided by nuclear and hydroelectric plants.[13]

As many power markets become highly dependent upon natural gas to provide resilience and reliability, the problems of fuel security have become more pronounced. Natural gas generation poses risks in providing reliability:

- Natural gas demand is at its peak for non-power uses (e.g., home heating) in cold weather at the same time as power demand.
- The total gas supply may not be adequate to meet the daily deliverability requirements for both heating and power in extended periods of extreme cold weather without on-site fuel storage.
- There is little or no on-site storage of fuel at CCGT gas plants:
  - Some CCGT plants have distillate oil fuel backup but keep little fuel in storage on site.
  - Many CCGT plants do not have the air permits for fuel oil storage facilities.
  - While CCGT plants theoretically could have liquified natural gas (LNG) storage on site, none of them have made this investment.

As the power system loses the diversity of supply of dispatchable fossil-fuel generation plants (oil has almost disappeared for power generation, and coal is declining rapidly), independent system operators are expressing concern about the over-reliance on natural gas for system reliability:

[12] Energy Information Administration, electricity data browser.
[13] Energy Information Administration Form 923 data for 2017.

- ISO New England has implemented changes to its capacity market because natural gas-fired plants were not able to meet their power performance obligations during cold winter weather when heating demand is high.[14]
- The FERC annual State of the Markets Report focused on concerns regarding fuel supply security for power generation during the cold snap (the "bomb cyclone") in early 2018 in New England and New York, causing power prices to exceed $1,000 per MWh and commissioners stated that New England "could face major reliability concerns."[15]

Summer power prices in the Electric Reliability Council of Texas (ERCOT) jumped in 2018 after Vistra announced the closure of three large coal-fired plants, reducing capacity and shifting dependence to natural gas. These three coal plants supplied 8.4 percent of the entire generation in ERCOT in 2017.

During the month of January 2018, when demand for power was high, across the entire eastern U.S. coal supplied 57 percent of the increased generation over the month of December, while natural gas only supplied 16 percent of the increase. It was the coal-fired plants that provided the increased power supply when needed, as natural gas was not available due to high demand for home heating. A total of 4.4 percent of total PJM generation during January 2018 was supplied by the three coal plants that are the focus of this study as well as other coal plants that have announced retirement plans.

TABLE 7: EASTERN POWER GENERATION DURING THE JANUARY 2018 COLD SNAP[16]

	Eastern US Total *(GWh)*			Change
Bomb Cyclone 2018	**Nov-17**	**Dec-17**	**Jan-18**	**Dec - Jan**
Coal	46,288	58,364	70,130	11,766
Natural Gas	54,148	59,889	63,192	3,303
Oil	237	1,077	4,426	3,349
Pet Coke	150	236	378	142
Fossil Total	**100,823**	**119,566**	**138,126**	**18,560**
Nuclear	52,464	57,768	58,739	971
Hydro	6,684	6,304	6,283	(21)
Wind	3,689	3,586	4,397	811
Solar	843	838	922	84
Geothermal	0	0	0	0
Biomass	1,980	2,087	2,107	20
Pumped Storage	(427)	(548)	(441)	107
Other	465	510	509	(1)
Non-Fossil	**65,698**	**70,545**	**72,516**	**1,971**
Total	**166,521**	**190,111**	**210,642**	**20,531**

The three-at-risk coal-fired plants analyzed in this study (Pleasants, Sammis and Bruce Mansfield) played a critical role in meeting power demand during the extreme cold weather events of 2018 and 2014. During the first week of January 2018 (the "bomb cyclone"), these three coal plants ran close to full capacity. These plants supplied 3.1 percent of the entire electricity in the PJM Interconnection during that week of high demand.

[14] S&P Global, "ISO New England phases in pay-for-performance incentives to keep the lights on", June 14, 2018.
[15] S&P Global, "FERC market report highlights fuel concerns for New England, California", April 19, 2018.
[16] Energy Information Administration, Form 923 data.

In PJM's report on the performance of its power system during the cold snap from December 28, 2017, to January 7, 2018, at the peak of demand on January 7, 2018, PJM identified almost 6,000 MW of natural gas capacity that was not available due to "gas supply issues" that were due to "transportation restrictions as well as spot gas commodity availability." In addition, over 8,000 MW of gas plant capacity was unavailable due to forced outages and over 9,000 MW of gas capacity switched to oil. PJM reported that "the majority of the reasons cited for the switch from gas to oil during the 2018 peak were a combination of interruptible gas curtailments by pipelines/LDCs or supply unavailability." In total, almost half of the natural gas generation capacity (23,350 MW) was unavailable at the peak of winter demand on January 7, 2018.[17]

Cost of Replacing the Three Coal Plants

Almost no new capacity cleared the 2021/2022 BRA auction (only 322 MW of new capacity was offered, and 261 MW cleared[18]), as merchant generators have found that the combination of the recent PJM capacity and energy prices are insufficient to support construction and operation of new power plants, even with the increase in capacity market prices. However, if 5,258 MW of coal plants are retired in 2019, this capacity will need to be replaced in the future.

The only type of replacement capacity that would provide similar levels of generation and reliable capacity is new combined cycle gas turbine (CCGT). Wind and solar plants run at very low capacity factors in PJM due to poor wind and solar resources compared to other areas of the country. Because of the unreliability of these technologies, PJM only credits a fraction of the installed capacity (ICAP) for wind (18 percent) and solar (60 percent) in calculating firm capacity resources for the Reliability Pricing Model (RPM) used in the BRA auction. As a result, PJM would require almost 30,000 MW of new wind capacity to replace the power provided by the 5,258 MW of coal plants.

The cost to replace the three coal plants with new gas-fired CCGT capacity would be $5.7 billion, using the capital cost estimate from EIA's Annual Energy Outlook of $1,084 per kW.[19] Excluding capital costs, the total operating cost for the coal and CCGT plants is similar. At current market prices, the cost of coal is about $1.80 per MMBtu, compared to the cost of natural gas (excluding the firm transportation cost) of $2.85 per MMBtu. Accounting for the higher efficiency of a new CCGT plant (about 6,600 Btu/kWh vs. 10,300 Btu/kWh for the three coal plants), the fuel cost per MWh for coal is about $18.54 vs. $18.81 for CCGT. While coal has higher non-fuel operating and maintenance cost, this is largely offset by the high fixed cost for firm gas transportation. Excluding capital (both initial capital and maintenance capital), the total operating cost for both plants at a 60 percent capacity factor is about $28 per MWh. With similar operating costs, the new capital cost of $5.7 billion will provide no savings for the PJM ratepayers and would have to be recovered in higher capacity prices.

In its September 2017 report, "Ensuring Resilient and Efficient Electricity Generation," IHS Markit analyzed the full cost of continuing to operate the existing U.S. coal fleet compared to the cost of replacing this portfolio with new CCGT plants and reached a similar conclusion. IHS Markit found that the "levelized going-forward costs" of the existing U.S. coal fleet averaged $40.20 per MWh, while the replacement cost for new CCGT power was almost $70 per MWh. The cost for an integrated mix of renewables and CCGT would be over $80 per MWh.[20]

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[17] PJM Interconnection, "PJM Cold Snap Performance, Dec. 28, 2017 to Jan. 7, 2018", February 26, 2018 at 13 – 17.

[18] PJM Interconnection, 2021-2022 base residual auction report, page 7. http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx?la=en

[19] Energy Information Administration, 2018 Annual Energy Outlook. https://www.eia.gov/outlooks/aeo/assumptions/

[20] IHS Markit, "Ensuring Resilient and Efficient Electricity Generation", September 2017, at 35 – 36.

Appendix A – PJM Coal Plant Retirements Since 2014

Since the Polar Vortex event in January 2014, 17,566 MW of coal-fired power plants in PJM have permanently stopped burning coal. Most of these plants (14,527 MW) have retired, while the remainder (3,039 MW) have switched to burning natural gas in the existing boiler. Plants which have switched to burning gas (primarily to comply with the MATS regulation) do not run at high capacity factors, but still provide capacity, if they have firm fuel supply. Another 3,422 MW of existing PJM coal plants have announced plans to retire or switch to gas through 2020.

				Retirement Date		
Plant	Unit	State	MW	Year	Month	Action
Announced Retirements						
Yorktown	1	VA	163	2018	6	Retire
Yorktown	2	VA	172	2018	6	Retire
Chesterfield	3	VA	102	2018	12	Retire
Chesterfield	4	VA	168	2018	12	Retire
Richmond/Spruance	1	VA	53	2019	1	Retire
Richmond/Spruance	2	VA	53	2019	1	Retire
Richmond/Spruance	3	VA	43	2019	1	Retire
Richmond/Spruance	4	VA	43	2019	1	Retire
Pleasants	1	WV	650	2019	1	Retire
Pleasants	2	WV	650	2019	1	Retire
Hopewell (James River)	1	VA	46	2019	3	Retire
Hopewell (James River)	2	VA	46	2019	3	Retire
BL England	2	NJ	155	2019	4	Switch to gas
Sammis	1	OH	180	2020	5	Retire
Sammis	2	OH	180	2020	5	Retire
Sammis	3	OH	180	2020	5	Retire
Sammis	4	OH	180	2020	5	Retire
Wagner	2	MD	135	2020	6	Retire
Colver	1	PA	110	2020	9	Retire
Rocky Mount (Edgecombe)	1	NC	58	2020	10	Retire
Rocky Mount (Edgecombe)	2	NC	58	2020	10	Retire
			3,422			

				Retirement Date		
Plant	Unit	State	MW	Year	Month	Action
Beckjord	4	OH	150	2014	2	Retire
BL England	1	NJ	129	2014	5	Retire
Portland	1	PA	158	2014	6	Retire
Portland	2	PA	243	2014	6	Retire
Sunbury	1	PA	82	2014	7	Retire
Sunbury	2	PA	82	2014	7	Retire
Sunbury	3	PA	91	2014	7	Retire
Sunbury	4	PA	134	2014	7	Retire
Beckjord	5	OH	238	2014	9	Retire
Beckjord	6	OH	421	2014	9	Retire
Chesapeake	1	VA	111	2014	12	Retire
Chesapeake	2	VA	111	2014	12	Retire
Chesapeake	3	VA	162	2014	12	Retire
Chesapeake	4	VA	221	2014	12	Retire
Miami Fort	6	OH	163	2015	4	Retire
Dale	1	KY	23	2015	4	Retire
Dale	2	KY	23	2015	4	Retire
Ashtabula	5	OH	244	2015	4	Retire
Eastlake	1	OH	132	2015	4	Retire
Eastlake	2	OH	132	2015	4	Retire
Eastlake	3	OH	132	2015	4	Retire
Lake Shore	18	OH	245	2015	4	Retire
Will County	3	IL	262	2015	4	Retire
Glen Lyn	5	VA	95	2015	6	Retire
Glen Lyn	6	VA	235	2015	6	Retire
Tanners Creek	1	IN	145	2015	6	Retire
Tanners Creek	2	IN	145	2015	6	Retire
Tanners Creek	3	IN	205	2015	6	Retire
Tanners Creek	4	IN	500	2015	6	Retire
Big Sandy	2	KY	800	2015	6	Retire
Muskingum River	3	OH	215	2015	6	Retire
Muskingum River	4	OH	215	2015	6	Retire
Muskingum River	5	OH	585	2015	6	Retire
Picway	5	OH	100	2015	6	Retire
Kammer	1	WV	210	2015	6	Retire
Kammer	2	WV	210	2015	6	Retire
Kammer	3	WV	210	2015	6	Retire
Kanawha River	1	WV	200	2015	6	Retire
Kanawha River	2	WV	200	2015	6	Retire
Sporn	1	WV	150	2015	6	Retire
Sporn	2	WV	150	2015	6	Retire
Sporn	3	WV	150	2015	6	Retire
Sporn	4	WV	150	2015	6	Retire
Clinch River	3	VA	235	2015	6	Retire

				Retirement Date		
Plant	Unit	State	MW	Year	Month	Action
Portsmouth	1	VA	58	2015	6	Retire
Portsmouth	2	VA	58	2015	6	Retire
Hutchings	1	OH	59	2015	6	Retire
Hutchings	2	OH	56	2015	6	Retire
Hutchings	3	OH	64	2015	6	Retire
Hutchings	5	OH	64	2015	6	Retire
Hutchings	6	OH	64	2015	6	Retire
Shawville	1	PA	128	2015	6	Switch to gas
Shawville	2	PA	130	2015	6	Switch to gas
Shawville	3	PA	180	2015	6	Switch to gas
Shawville	4	PA	180	2015	6	Switch to gas
Clinch River	1	VA	235	2015	8	Switch to gas
Clinch River	2	VA	235	2015	8	Switch to gas
Beaver Valley	1	PA	152	2015	9	Retire
Joliet	6	IL	314	2016	2	Switch to gas
New Castle	3	PA	98	2016	3	Switch to gas
New Castle	4	PA	98	2016	3	Switch to gas
New Castle	5	PA	137	2016	3	Switch to gas
Joliet	7	IL	522	2016	3	Switch to gas
Joliet	8	IL	522	2016	3	Switch to gas
Big Sandy	1	KY	260	2016	4	Switch to gas
Dale	3	KY	75	2016	4	Retire
Dale	4	KY	75	2016	4	Retire
Avon Lake	7	OH	96	2016	4	Retire
ROVA	1	NC	167	2017	3	Retire
ROVA II	2	NC	45	2017	3	Retire
Hudson	2	NJ	620	2017	6	Retire
Mercer	1	NJ	325	2017	6	Retire
Mercer	2	NJ	325	2017	6	Retire
Stuart	1	OH	577	2017	9	Retire
Mecklenburg	1	VA	69	2018	4	Retire
Mecklenburg	2	VA	69	2018	4	Retire
Crane	1	MD	190	2018	6	Retire
Crane	2	MD	195	2018	6	Retire
Killen	2	OH	600	2018	6	Retire
Stuart	2	OH	577	2018	6	Retire
Stuart	3	OH	577	2018	6	Retire
Stuart	4	OH	577	2018	6	Retire
Retired Through June 2018			**17,566**			