BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

IN THE MATTER OF THE LONG-TERM FORECAST REPORT OF OHIO POWER COMPANY AND RELATED MATTERS.	)))	CASE NO.: 18-501-EL-FOR
IN THE MATTER OF THE APPLICATION SEEKING APPROVAL OF OHIO POWER COMPANY'S PROPOSAL TO ENTER INTO RENEWABLE ENERGY PURCHASE AGREEMENTS FOR INCLUSION IN THE RENEWABLE GENERATION RIDER.	))))))	CASE NO.: 18-1392-EL-RDR
IN THE MATTER OF THE APPLICATION OF OHIO POWER COMPANY TO AMEND ITS TARIFFS.	)))	CASE NO.: 18-1393-EL-ATA

DIRECT TESTIMONY OF
EMILY S. MEDINE
ON BEHALF OF THE OHIO COAL ASSOCIATION (OCA)

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Emily S. Medine. I am a Principal in the consulting firm of Energy Ventures Analysis, Inc. ("EVA"). My business address is 1901 N. Moore Street, Suite 1200, Arlington, Virginia 22209-1706.

Q. PLEASE DESCRIBE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I have been with EVA, an energy consultancy formed in 1981, since 1986. EVA engages in a variety of energy-related projects for private and public sector clients. Prior to EVA, I worked for Consolidation Coal Company (now "CONSOL Energy"). I received a Bachelor of Arts degree from Clark University in 1976 and a Masters of Public Affairs from the Woodrow Wilson School of Public and International Affairs at Princeton University in 1978.

My education and experience are set out in Attachment ESM-1.

Q. PLEASE DESCRIBE EVA.

A. EVA is a consulting firm that engages in a variety of projects for private and public sector clients related to energy and environmental issues. EVA also has a subscription business and currently produces about 15 publications, the frequency of which range from weekly to annual. In the energy area, much of our work is related to analysis of the electric utility industry and fuel markets, particularly oil, natural gas and coal. Our clients in these areas include coal, oil and natural gas producers, electric utility and industrial energy consumers, and gas pipelines and railroads. We also work for a number of public agencies, including the U.S. Department of Justice, the U.S. Department of the Interior, state public utility commissions, as well as intervenors in utility rate proceedings, such as consumer counsels and municipalities. Another group of clients include trade and industry associations. EVA has provided testimony in numerous state public utility commissions. Principals in the firm have also filed testimony in a number of cases in both state and federal courts, as well as before the Federal Energy Regulatory Commission.

Q. WHO ARE YOU TESTIFYING ON BEHALF?

A. My testimony is on behalf of the Ohio Coal Association (OCA) and at the request of their counsel, Benesch, Friedlander, Coplan & Aronoff, LLP.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony is to provide the history of the Renewable Generation Rider (RGR), AEP Ohio's application related to establishing need for the 900 MW of renewables in the Settlement Agreement, construction of the Request for Proposal for the solar renewable projects, its analysis of bids, and its selection process, AEP Ohio's performance with respect to the Alternative Energy Rider, and changes in the renewable generation market that eliminate the need for the type of Renewable Energy Purchase Agreements (REPA) for which AEP Ohio is seeking approval.

Q. PLEASE SUMMARIZE THE FINDINGS OF YOUR REVIEW.

A. Finding #1: AEP Ohio fulfilled its obligation to propose to develop 400 MW of solar renewable generation facilities. There is no obligation for the PUCO to accept AEP Ohio's proposal unless it satisfies a "need" and provides cost containment for AEP Ohio customers.[1]

Finding #2: AEP Ohio did not demonstrate a "need" for these projects. As AEP did not established a resource need, AEP Ohio focused on a customer survey which was not statistically significant to demonstrate a customer preference was a need. The data did not show this. To the extent any conclusion was reached, it showed customers would prefer Ohio renewable power only if it was cost competitive.

Finding #3: The RFPs that were conducted on behalf of AEP Ohio were not designed to determine whether Ohio renewable development through a 20-year nonbypassable rider was cost competitive as opposed to other options.

Finding #4: The analysis of the RFPs did not demonstrate the REPAs are cost competitive or provided cost containment. In addition, the analysis failed to consider all available options including the retention of existing

[1] https://www.puco.ohio.gov/be-informed/consumer-topics/aep-ohio-power-purchase-agreement-rider/

generating capacity until such time that renewables would be cost competitive without a nonbypassable rider.

Finding #5: AEP Ohio did not demonstrate that the development of the solar projects is urgently needed or will advance further development of renewable projects in Ohio or elsewhere. Ohio does not have quality solar resources. Even when cost recovery of in-state solar renewable energy credits was mandated, the Governor and State Assembly chose to eliminate the in-state requirement due to its higher costs.

Finding #6: Significant advances have been made with respect to the development of renewables and battery storage resulting in declining costs and prices. Solar development is expected to continue apace regardless of the decline in the Investment Tax Credit. A commitment to 20-year REPAs for in-state solar projects present significant economic risk to AEP Ohio customers and is not in AEP Ohio customers' best interest.

Finding: #7: AEP Ohio's requested debt equivalency payment is not a standard industry provision for REPAs or PPAs and is not specifically contemplated in the Settlement Agreement. The Settlement Agreement does give AEP Ohio the right to own up to 50 percent of any project it develops. The fact that AEP Ohio declined such ownership and chose to request a debt equivalency payment suggests it determined the debt equivalency payment was of more value than equity ownership. Further, the debt equivalency payment does not appear to be included in AEP Ohio's evaluation of the REPAs.

Finding #8: To the extent that a segment of AEP Ohio's customer base wants additional Ohio renewables a better and more equitable alternative would be through a voluntary green tariff or through a Community Solar project.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. The PUCO should find that AEP Ohio did not demonstrate a need for the 400 MW of solar renewables and should not approve AEP Ohio's request to approve the REPAs for the two solar projects.

The proposed voluntary Green Tariff for Renewable Energy Credits is reasonable and could be expanded to include voluntary participation in renewable projects.

Q. WHAT INFORMATION DID YOU RELY UPON IN THE PREPARATION OF THIS TESTIMONY?

A, In addition to general industry knowledge, EVA databases, and cited reports and articles, I relied upon the following:

- The Company's public filings under these cases as well as under related cases
- Non-confidential responses from the Company to Data Requests from the OCA and other parties
- State Supreme Court Decision on Cases 14-1693-EL-RDR and 14-1694-EL-AAM
- Public Utilities Commission of Ohio website
- Recent Integrated Resource Plans from other utilities
- Energy Information Administration data are reports

Q. HOW IS THE REST OF YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

- History of the Renewable Generation Rider
- AEP Ohio Application
- Demonstration of Need for Solar REPAs
- Changes in the Renewable Generation Market

II. HISTORY OF THE RENEWABLE GENERATION RIDER

Q. WHAT IS RENEWABLE GENERATION RIDER (RGR)?

A. AEP Ohio proposed the RGR in Cases 14-1693-EL-RDR and 14-1694-EL-AAM recognizing a potential need for AEP Ohio to develop new capacity resources during the extended term of the Amended ESP. The RGR was proposed as a nonbypassable rider under R.C. 4928.143(B)(2)(b) and (c).

Q. WHAT BENEFITS DID COMPANY WITNESSES ASCRIBE TO THE RGR?

A. Company Witness Allen stated that from a financial perspective the "proposal is essentially equivalent for customers (to the PPA rider mechanism)"[2] although Company Witness Allen acknowledged later on in the same testimony that in fact it would not be same. The PPA rider mechanism is only for the ESP term while the RGR would be for the life of the facility.[3] Company Witness Moore states in her testimony that the benefits of the RGR would include "payroll taxes associated with jobs in both construction and thereafter during the operation of the facility, purchase of Ohio goods and services and taxes that provide critical funding for Ohio schools, infrastructure and public services."[4]

Q. HOW DID THE ESP FILING CONTEMPLATE HOW THE RGR WOULD BE CALCULATED?

A. It did not. The ESP proposal looked at the RGR as a placeholder nonbypassable rider. According to Company Witness Gill, the timing and outcome any (RGR proceeding) is unknown … therefore "the Company has no basis to prepare an estimate of the potential RGR rates."[5]

Q. WHAT DID THE OPINION AND ORDER SAY ABOUT THE RGR?

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[2] Direct Testimony of Company Witness William A. Allen, Case 16-1852, Page 9, Lines 18-19.
[3] Direct Testimony of Company Witness William A. Allen, Case 16-1852Page 10, Lines 3-5e
[4] Direct Testimony of Andrea E. Moore, Case 16-1852 Page 9, Lines 9-11.
[5] Direct Testimony of David R. Gill, Case 16-1852, Page 9, Lines 14-17.

A. The Opinion and Order reflected the Settlement Agreement reached by what is referred to as the Signatory Parties. The Settlement Agreement provided for recovery of approved new renewable generation projects to be through a new nonbypassable RGR. As no projects were approved in the ESP proceeding, the RGR was referred to as a placeholder RGR for when/if such projects requiring recovery were approved. The Opinion and Order made clear that "all parties reserve their right to contest individual renewable projects" … "including the right to challenge the Company's statutory authority to propose such projects, or other projects using RGR for collection."[6]

Q. WHAT DETAILS WERE PROVIDED AS TO THE ENERGY PROJECTS TO BE DEVELOPED?

A. Section III.I of the Opinion and Order states the following:

1. AEP Ohio and its affiliates will develop a total of at least 500 MW nameplate capacity of wind energy projects in Ohio as follows:

   a. The individual projects will be proposed over the course of the next four years, following adoption of the stipulation.

   b. AEP Ohio will file EL-RDR applications under the PPA rider to initiate for retail cost recovery associated with each project. AEP Ohio agrees to use its best efforts to seek Commission approval for these filings.

   c. AEP affiliates will have the right, based on commercially reasonable term, to initially own up to 50 percent of such projects on an aggregate net basis based upon installed capacity. Ownership details will be established for each project individually. Such projects will be competitively bid. AEP will consult with Staff regarding the process by which projects are selected for advancement. The request for proposal process will be commenced within 45 days of a Commission order adopting the stipulation. Subject to timely regulatory approvals , the projects will commence construction by the deadline for eligibility of benefits available under the CPP. The projects are not contingent on the CPP taking effect.

[6] Opinion and Order paragraphs 50 and 51

d. AEP Ohio will be the buyer of a long-term PPA (i.e., 10 years or longer) for each project including all capacity, energy, ancillaries, and renewable energy credits produced by the project. Capacity, energy, and ancillary services for all projects will be liquidated into the PJM markets with resulting revenues being credited to retail customers. Renewable energy credits not reserved for compliance will be liquidated into the markets with resulting revenues being credited to retail customers.

e. The commitment is premised upon AEP Ohio receiving full cost recovery based upon a PPA structure (through the PPA Rider with details (except for the rate design provided for below) to be determined as part of the separate EL-RDR filing. In reviewing such application, the Commission will consider, among other relevant matters, the economics and proposed PPA price associated with each project, as compared to other available market prices for such projects.

f. The wind energy projects will be completed by 2021 subject to timely regulatory approvals

2. AEP Ohio will develop a total of at least 400 MW nameplate capacity for a solar energy project(s) in Ohio, subject to Commission approval and cost recovery (based on a PPA structure) through the PPA rider with details (except for the rate design provided for below) to be determined as part of the separate EL-RDR filing. The same approach and parameters described above in Sections Ill.I.l.a through Ill.I.l.e of the stipulation will apply to the solar project(s). In lieu of Section III.I.l.f that is applicable to the wind energy projects, AEP Ohio and its affiliates will commit to use best efforts to complete the solar energy projects by 2021. In addition, preference will be given to solar projects that are sited in Appalachian Ohio, create permanent manufacturing jobs in Appalachian Ohio, and commit to hiring Ohio military veterans.

Q. WAS THE OPINION AND ORDER IN THE ESP CASE CONTESTED?

A. Yes. A number of parties filed for rehearing. With respect to the RGR projects, PUCO Chairman Asim Z. Haque of the PUCO noted in the Second Entry on Rehearing[7] that while "AEP has the authority … to develop up to 900 MW of utility-scale wind (500 MW) and solar (400 MW) … **cost containment** will be key in determining whether or not the project receives the requisite approval." This position is confirmed in the body of the Second Entry on Rehearing which states that the Commission finds "OCC's concerns regarding the potential costs associated with any renewable energy project to be proposed are premature at this point, **as any cost recovery filing that occurs will be subject to the review of the Commission.**" (emphasis added)[8]

Ultimately there was an Ohio Supreme Court challenge, the order from which was issued November 27, 2018. The Ohio Supreme Court affirmed the PUCO decision in Cases 14-1693-EL-RDR and 14-1694-EL-AAM.[9] With respect to the RGR, the relevant sections are repeated below:

¶ 36} OCC first argues that the commission erred when it refused to consider the costs of certain renewable energy projects in conducting the statutory test. The commission had previously authorized Ohio Power to develop 900 megawatts of renewable energy projects in the four years following the adoption of the stipulation in this case and also to recover the costs of those resources through the PPA Rider. OCC maintains that these "costs were expected to be collected from customers during the ESP," so they should have been considered when evaluating the ESP under R.C. 4928.143(C)(1).

{¶ 37} We see no error in the commission's decision on this point. The commission explained that it did not consider these costs under the statutory test because no renewable project costs were being recovered during the period covered by this ESP. The renewable energy projects at issue were to be developed in the future and the commission would determine any cost recovery in Ohio Power's next ESP case. As for OCC's claim that "costs were expected to be collected from customers during the ESP," it offers no evidence to support that assertion. We therefore reject OCC's argument on this point.

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[7] https://dis.puc.state.oh.us/TiffToPDf/A1001001A16K03B42232J00062.pdf, pages 6-7 of Concurring Opinion of Chairman Asim Z. Haque
[8] https://dis.puc.state.oh.us/TiffToPDf/A1001001A16K03B42232J00062.pdf, page 58
[9] http://www.supremecourt.ohio.gov/rod/docs/pdf/0/2018/2018-Ohio-4698.pdf

Q. WHAT IS THE STATUS OF THE AEP ESP?

A. In November 2016, AEP Ohio filed a proposal to modify and extend its third ESP through May 2024 (referred to as ESP IV). On August 25, 2017, AEP Ohio, PUCO staff and numerous other parties reached a settlement agreement in this electric security plan case which the PUCO modified and approved. ESP IV continues to use a competitive bidding process to establish default generation rates for AEP Ohio's customers who have not elected to receive service from a competitive supplier. The ESP IV order retained AEP Ohio's obligation to propose renewable energy projects and requires AEP Ohio to demonstrate need for electric generating facilities based on Company-submitted resource planning projections before the Commission will authorize recovery of the costs of those facilities.

III. AEP OHIO APPLICATIONs

Q. WHEN DID AEP OHIO FILE AN APPLICATON

A. AEP Ohio filed its 2018 long-term forecast report (LTFR) on April 16, 2018. On September 19, 2018, AEP Ohio submitted an amendment to the 2018 LTFR to demonstrate the need for at least 900 MW of renewable energy projects in Ohio. On September 27, 2018, AEP Ohio submitted a separate application seeking approval to enter into two solar renewable energy purchase agreements (REPA) for inclusion in the RGR.

Q. PLEASE DESCRIBE THE REPA'S FOR WHICH AEP OHIO IS SEEKING APPROVAL.

A. AEP Ohio is seeking approval to enter into a REPA with Highland Solar, a 300 MW nameplate capacity solar facility and with Willowbrook Solar, a 100 MW nameplate capacity solar facility. In the application, AEP Ohio indicated that it had executed 20-year renewable energy purchase agreements (REPA) for the projects' energy, capacity, and environmental attributes.

AEP Ohio is also requesting approval for a new Green Tariff which will give all customer classes the opportunity to purchase renewable energy credits (RECs) to cover some or all of their usage – whether served by AEP Ohio's standard service offer or by a competitive retail electric service provider. According to the Application, "the Green Tariff enables customers to support the development of in-state renewable energy resources in another way, by giving them the option to purchase green power that reflects some, all, or more than all of their load. Customers' participation in the Green Tariff will produce revenues that will offset a portion of the net cost of the Highland Solar and Willowbrook Solar REPAs (i.e., the net cost after liquidating the output of the facilities into the PJM markets). The Green Tariff also promotes economic development for commercial and industrial customers interested in maintaining or expanding operations in the Company's service territory while supporting sustainability and carbon emissions reduction goals."

Q. WHY IS A DEMONSTRATION OF NEED A REQUIREMENT?

A. According to AEP Ohio, it must demonstrate need for any proposed projects which is based upon whether a project "can be developed within a reasonable price" and that the projects would provide "rate stability" for customers.[10]

[10] https://dis.puc.state.oh.us/TiffToPDf/A1001001A18I19B53347A02011.pdf

IV. DEMONSTRATOIN OF NEED FOR SOLAR REPAS

Q. HOW DOES AEP OHIO DEMONSTRATE NEED?

A. AEP Ohio represents it demonstrates need (1) through the use of a competitive solicitation, (2) through a comparison of project costs against generation alternatives, (3) through the location of the projects in the state of Ohio, (4) through the dedication of the projects to AEP Ohio customers, and (5) through the determination that AEP Ohio customers have a stated desire for such in-state projects. Notably a shortage of resources is not the basis of AEP Ohio's demonstration of need.

Q. DO YOU AGREE WITH ANY OF THE DEFINITIONS OF NEED USED BY AEP OHIO?

A. No nor would any economist. In terms of economics, a "need" would be defined as a good or service that is required which is in contrast to a "want" which is a good or service that is not necessary but something desired or wished for. In terms of renewable energy, the "need" is for electricity consistent with regulatory requirements. A "want" is perhaps green electricity that produces little to no carbon footprint and that supports the economy of Ohio. In Ohio, the only statutory requirement for utilities related to renewables derives from the Alternative Energy Portfolio Standard as amended.[11] The costs associated with the alternative energy requirements are recovered through the Alternative Energy Rider (AER). What AEP Ohio is proposing are projects which meet a nebulous "want" that it has not demonstrated to be a real "need".

Q. PLEASE REVIEW AEP'S JUSTIFICATIONS THAT THESE PROJECTS ARE NEEDED TO ADDRESS A NEED.

A. **<u>(1) Request for Proposal</u>**

The Direct Testimony of Company Witness Daniel Bradley describes the RFP process. Witness Bradley works for Navigant, a company engaged by AEP Ohio to be the "Independent Evaluator" for the Solar RFP. According to Witness Bradley, AEP Ohio

[11] See Attachment ESM-2

requested bids to obtain up to 400 MW of nameplate-rated Solar Energy Resources through a REPA for 20 years under which AEP Ohio would purchase the facilities' renewable energy products (energy, capacity, ancillary services and environmental attributes). Navigant was engaged to assist in the development of the RFP, the development of bid procedures and the scoring methodology. Using the RFP responses and the bid and scoring methodology, Navigant then evaluated the bids.

There were three clear flaws to the RFP itself. First, the ESP settlement contained in the Opinion and Order included renewable PPAs for 10 years or more, not 20 years. As a result the requirement that the bids be for 20 years was inconsistent with the Opinion and Order. At a minimum, the RFP should have requested bids with a minimum of 10 years and let the bidders speak to terms. Alternatively, and preferably, the RFP should have asked for bids with different terms. The term issue is of particular importance given the stated goal is cost containment.

The historic declines in cost of solar as shown in Exhibit ESM-1 demonstrate that a commitment to a solar plant in 2010 would have been out of the money in 20 years. Encumbering customers to a 20-year term is ill-advised and not consistent with the Settlement. Further, this is a mistake AEP Ohio previously made to the detriment of its customers. In or around 2009, AEP Ohio entered in long-term contracts for wind.[12] Declines in the price of wind since those contracts were signed has been significant and are believed to have resulted in the AER costs for AEP Ohio being a multiple of the AER costs of the other Ohio utilities.[13]

[12] AEP Press Release, February 2, 2009.
[13] See Attachment ESM-2

Exhibit ESM-1. DECLINING SOLAR PV COSTS[14]

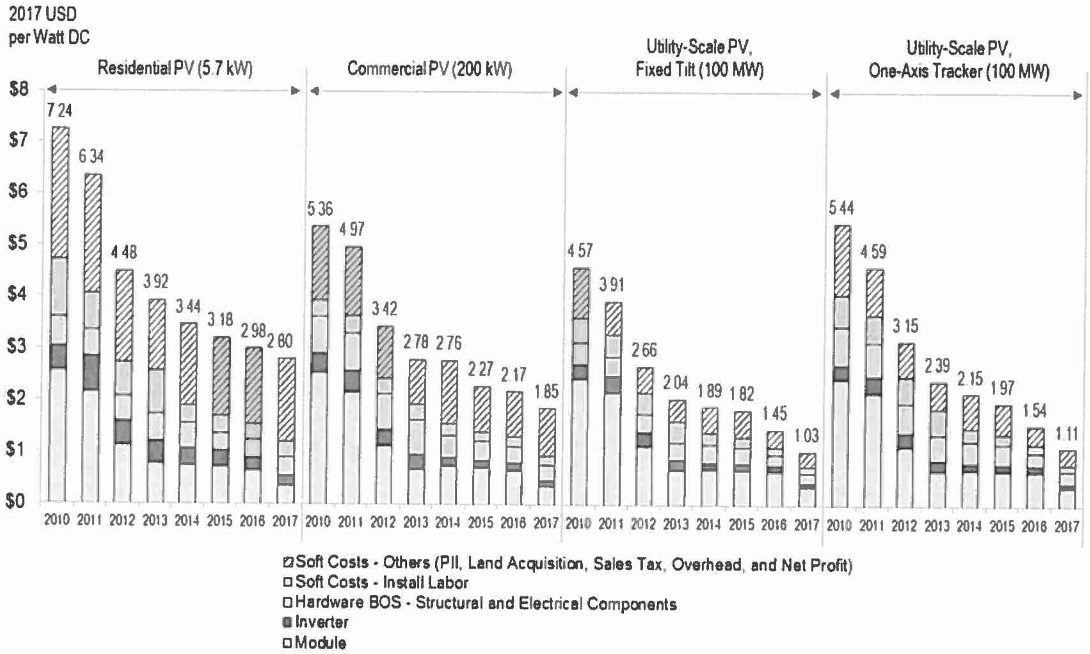
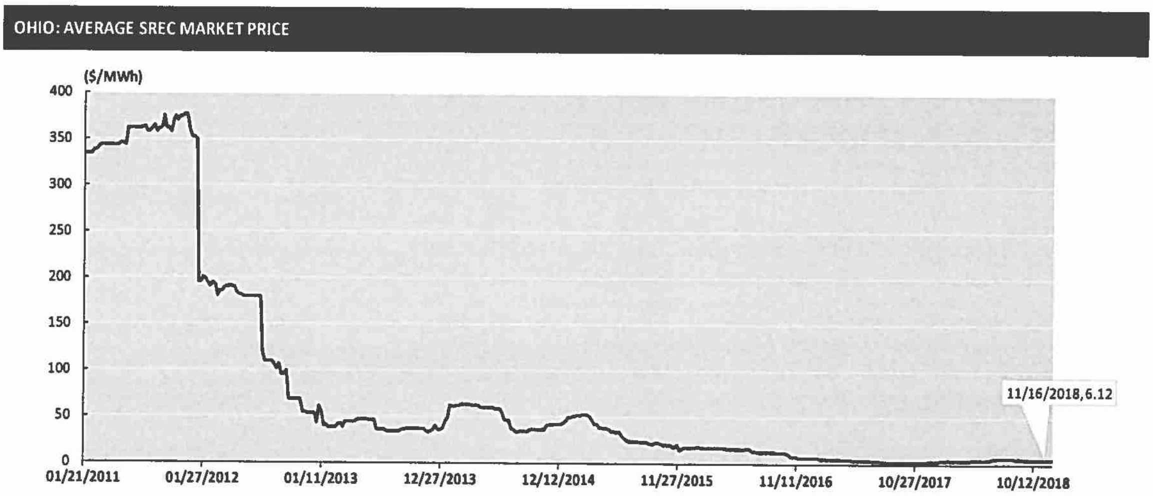


Figure ES-1. NREL PV system cost benchmark summary (inflation adjusted), 2010–2017

Not surprisingly, the drop in solar costs translated into a drop in the prices of Ohio Solar Renewable Energy Credits. (SRECs), As shown is Exhibit ESM-2, the reported Ohio SREC prices plummeted in 2012 to under $50 per megawatt-hour. The Ohio SREC pricing plummeted again in 2015 after the in-state renewables requirement in the Alternative Energy Portfolio Standard was eliminated. Currently, the very low SREC prices reflect sufficient availability of SRECs to meet state benchmark requirements.

[14] : https://www.nrel.gov/docs/fy17osti/68925.pdf, page vi.

Exhibit ESM-2. OHIO SOLAR REC PRICES



Source: SNL, EVA

The second flaw, which could have eliminated some of the problem associated with the first flaw, is the reported fixed 20-year term of the REPA agreement. This is a problem for AEP Ohio customers if the costs under the REPA diverge significantly from market. There are a number of options to achieve term flexibility such as a shorter term with extension options or an exit ramp which could include a pre-negotiated termination payment and/or the right to purchase the plant at formula-based number. While term flexibility may have resulted in a higher price in the initial years, higher payments during a shorter (if in fact the need existed) could well be worth the avoidance of higher costs in the long term. Regardless, since AEP Ohio chose not to consider a 10-year PPA through the RFP, prudence requires protection from market changes in the 20-year REPA agreements.

The third flaw relates to the RFP provision which requires bidders to afford the right for an AEP Ohio affiliate to purchase up to 50 percent of the facility. While there is no debate that the Opinion and Order gives AEP Ohio this right, had the RFP not required every party to agree to this right, the RFP would have provided more information as to whether the obligation to provide this right affected the bid prices, hence affecting the desired cost containment.

Given the three flaws with the process, the only conclusion that can be reached from the RFP's relates to the specific scope of the RFP, i.e., a 20-year PPA with no apparent exit ramps that provides AEP Ohio a unilateral buy-in right. The RFP did not determine what the lowest cost solar option would be.

Finally, an additional problem with the RFP is the in-state requirement. The Settlement Agreement states that "(i)n reviewing (the) application, the Commission will consider, among other relevant matters, the economics and proposed PPA price associated with each project, as compared to **other available market prices** for such projects." A question remains as to whether the intent of the Settlement Agreement was to limit "such projects" to such projects in Ohio. This language does not include "in Ohio" so reasonably it can be argued such a limitation does not exist. If this is the case, the in-state limitation in the RFP is problematic as no out-of-state bids were received and therefore there is no basis for such a conclusion.

The likelihood that the RFP results do **not** provide cost containments for AEP Ohio customers is effectively acknowledged in the Integrated Resource Planning Report for AEP Ohio which states "advancements in both solar photovoltaics and wind turbine manufacturing have reduced both installed and ongoing costs, renewable resources are becoming increasingly economical, and many customers want clean energy at a reasonable cost" and large scale solar is projected "to be substantially lower in costs compared to other sectors."[15] This finding is further confirmed in the recent Integrated Resource Plan (IRP) for Northern Indiana Public Service Company which conducted an RFP as part of its IRP process. The average price for solar under the IRP was $35.67 per kilowatt hour. As the average price reflects 16 bids accounting for significantly more capacity than the 400 MW AEP Ohio is seeking, the average price for the lowest cost 400 MW would be less.[16]

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[15] Exhibit JFT-1 to the Direct Testimony of John F. Torpey on behalf of Ohio Power Company, Case No. 18-501-EL-FOR, September 19th, 2018, pages 9 and 12.
[16] https://www.nipsco.com/docs/default-source/default-document-library/2018-nipsco-irp.pdf,Appendix A page 338

(2) **Comparison with Other New Resource Optionss**

Company Witness Torpey[17] presents a long-term cost benefit analysis for the specific 20-year Renewable Energy Purchase Agreements (REPAs). The small positive net present value (NPV) is about 0.1 percent of the total NPV.

Table 4. PJM Impact Applied to AEP Ohio Load

AEP LMPs										
Base Load LMPs w/o Renewables					Combined Renewable Load LMPs					Change
Year	Present Value Factor	Load Cost ($Mil)	OPCo Load (GWh)	Load Energy Cost ($/MWh)	Year	Present Value Factor	Load Cost ($Mil)	OPCo Load (GWh)	Load Energy Cost ($/MWh)	Load Energy Cost ($/MWh)
2021	0.9217	$1,642	46,249	$35.51	2021	0.9217	$1,640	46,249	$35.46	-$0.05
2022	0.8495	$1,721	46,233	$37.23	2022	0.8495	$1,719	46,233	$37.19	-$0.04
2023	0.7829	$1,807	46,372	$38.97	2023	0.7829	$1,806	46,372	$38.94	-$0.03
2024	0.7216	$1,892	46,445	$40.74	2024	0.7216	$1,891	46,445	$40.72	-$0.02
2025	0.6650	$1,980	46,441	$42.63	2025	0.6650	$1,978	46,441	$42.59	-$0.03
2026	0.6129	$2,069	46,452	$44.55	2026	0.6129	$2,067	46,452	$44.50	-$0.05
2027	0.5649	$2,160	46,535	$46.41	2027	0.5649	$2,156	46,535	$46.34	-$0.07
2028	0.5207	$2,774	46,712	$59.38	2028	0.5207	$2,770	46,712	$59.30	-$0.08
2029	0.4799	$2,851	46,920	$60.76	2029	0.4799	$2,847	46,920	$60.68	-$0.09
2030	0.4423	$3,021	47,108	$64.13	2030	0.4423	$3,017	47,108	$64.04	-$0.09
2031	0.4076	$3,152	47,335	$66.58	2031	0.4076	$3,147	47,335	$66.49	-$0.09
2032	0.3757	$3,265	47,595	$68.60	2032	0.3757	$3,261	47,595	$68.51	-$0.10
2033	0.3463	$3,410	47,884	$71.21	2033	0.3463	$3,405	47,884	$71.11	-$0.10
2034	0.3191	$3,515	48,178	$72.97	2034	0.3191	$3,511	48,178	$72.87	-$0.10
2035	0.2941	$3,656	48,467	$75.44	2035	0.2941	$3,651	48,467	$75.33	-$0.11
2036	0.2711	$3,798	48,734	$77.93	2036	0.2711	$3,793	48,734	$77.82	-$0.11
2037	0.2499	$3,912	48,978	$79.87	2037	0.2499	$3,906	48,978	$79.75	-$0.11
2038	0.2303	$4,095	49,196	$83.24	2038	0.2303	$4,089	49,196	$83.12	-$0.12
2039	0.2122	$4,149	49,407	$83.97	2039	0.2122	$4,143	49,407	$83.85	-$0.12
2040	0.1956	$4,319	49,618	$87.04	2040	0.1956	$4,313	49,618	$86.92	-$0.12
NPV	9.4633	$24,274	445,395		NPV	9.4633	$24,244	445,395		
Levelized		$2,565	47,065	$54.50	Levelized		$2,562	47,065	$54.43	-$0.07
					NPV Change ($Mil)		($31)			

No serious analyst would argue that a 0.12 percent difference over a 20-year period demonstrates that one scenario is lower in cost than another. This difference is well within the margin of error of the forecasts. Said differently, a microscopic change in any number of assumptions could reverse the outcome. Therefore, for decision-making purposes, the results are not dispositive despite AEP Ohio's representation to the contrary.

[17] Case No. 18-501-EL-FOR, Direct Testimony of John F. Torpey on behalf of Ohio Power Company, September 19th, 2018.

In fact, many of the assumptions appear problematic. For example, the average annual growth rate in energy costs is very high at over 4.5 percent. The cost for the new resource options, shown below, are inconsistent with other reported costs.

Table 1. New Generation Technology Options with Key Assumptions

AEP System-East Zone
New Generation Technologies
Key Supply-Side Resource Option Assumptions (a)(b)(c)

Type	Capability (MW) (g) Std. ISO	Winter	Summer	Installed Cost (c,d) ($/kW)	Full Load Heat Rate (HHV, Btu/kWh)	Fuel Cost (f) ($/MBtu)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	SO2 (Lb/mmBtu)	Emission Rates NOx (Lb/mmBtu)	CO2 (Lb/mmBtu)	Capacity Factor (%)	Overall Availability (%)	LCOE (k) ($/MWh)
Base Load														
Nuclear	1,610	1,600	1,560	7,400	10,500	1.2	6.2	143.5	0.0000	0.000	0.0	90	94	171.7
Base Load (90% CO2 Capture New Unit)														
Pulv. Coal (Ultra-Supercritical) (PRB)	540	570	520	6,900	12,500	4.4	5.6	96.8	0.0850	0.050	21.3	85	90	244.0
Base / Intermediate														
Combined Cycle (1X1 "J" Class)	540	570	700	1,200	6,300	7.2	2.0	7.3	0.0007	0.007	117.1	60	89	87.2
Combined Cycle (2X1 "J" Class)	1,083	1,140	1,410	900	6,300	7.2	1.7	4.6	0.0007	0.007	117.1	60	89	78.7
Combined Cycle (2X1 "H" Class)	1,150	1,210	1,500	900	6,300	7.2	1.6	4.3	0.0007	0.007	117.1	60	89	75.9
Peaking														
Combustion Turbine (2 - "E" Class) (h)	182	190	190	1,200	11,700	7.2	3.9	9.4	0.0007	0.006	117.1	25	93	177.3
Combustion Turbine (2 - "F" Class, w/evap coolers) (h)	458	510	500	700	10,000	7.2	6.1	5.0	0.0007	0.006	117.1	25	93	139.3
Aero-Derivative (2 - Small Machines) (h,i)	120	120	130	1,400	9,700	7.2	2.4	38.9	0.0007	0.006	117.1	25	97	175.4
Recip Engines (12 - w/SCR, Natural Gas Only)	220	240	220	1,200	6,300	7.2	5.4	6.0	0.0007	0.006	117.1	25	96	148.0
Storage Battery (4 Hour-Lithium Ion)	10	10	10	2,200	87% (j)	–	–	142.3	–	–	–	25	90	275.0

Notes: (a) Installed cost, capability and heat rate numbers have been rounded
(b) All costs in 2018 dollars. Assume 2.17% escalation rate for 2018 and beyond
(c) $/kW costs are based on nominal capability
(d) Total Plant Investment Cost w/AFUDC (AEP-East rate of 5.5%, site rating $/kW)
(f) Levelized Fuel Cost (40-Yr. Period 2018-2057)
(g) All Capabilities are at 1,000 feet above sea level
(h) Includes Dual Fuel capability and SCR environmental installation
(i) Includes Black Start capability
(j) Denotes efficiency, (w/ power electronics)
(k) Levelized cost of energy based on assumed capacity factors shown in table

The Energy Information Administration (EIA) assumptions to its 2018 Annual Energy Outlook are provided below. While tables are not exactly comparable, there are material differences with respect to coal. EIA includes 90 percent CO_2 capture but also includes 30 percent CO_2 captures which EIA notes is consistent with the existing New Source Performance Standard (NSPS) for Greenhouse Gases (GHG). The assumed heat rate for both the 90 and 30 percent options are considerably better than what AEP Ohio assumes. Of note, the Environmental Protection Agency (EPA) has recently proposed to replace the NSPS for GHG which if finalized would be based on commercial technology and allow a new high efficiency low emission (often referred to as HELE) technology with a heat rate likely below 9,000 Btu per kilowatt-hour.

Table 2. Cost and performance characteristics of new central station electricity generating technologies

Technology	First available year[1]	Size (MW)	Lead time (years)	Base overnight cost (2017 $/kW)	Project Contin-gency Factor[2]	Techno-logical Optimism Factor[3]	Total overnight cost[4,10] (2017 $/kW)	Variable O&M[5] (2017 $/MWh)	Fixed O&M (2017$/ kW/yr)	Heat rate[6] (Btu/kWh)	nth-of-a-kind heat rate (Btu/kWh)
Coal with 30% carbon sequestration (CCS)	2021	650	4	4,641	1.07	1.03	5,089	7.17	70.70	9,750	9,221
Coal with 90% CCS	2021	650	4	5,132	1.07	1.03	5,628	9.70	82.10	11,650	9,257
Conv Gas/Oil Combined Cycle (CC)	2020	702	3	935	1.05	1.00	982	3.54	11.11	6,600	6,350
Adv Gas/Oil CC	2020	429	3	1,026	1.08	1.00	1,108	2.02	10.10	6,300	6,200
Adv CC with CCS	2020	340	3	1,936	1.08	1.04	2,175	7.20	33.75	7,525	7,493
Conv Combustion Turbine[7]	2019	100	2	1,054	1.05	1.00	1,107	3.54	17.67	9,880	9,600
Adv Combustion Turbine	2019	237	2	648	1.05	1.00	680	10.81	6.87	9,800	8,550
Fuel Cells	2020	10	3	6,192	1.05	1.10	7,132	45.64	0.00	9,500	6,960
Adv Nuclear	2022	2,234	6	5,148	1.10	1.05	5,946	2.32	101.28	10,460	10,460
Distributed Generation - Base	2020	2	3	1,479	1.05	1.00	1,553	8.23	18.52	8,969	8,900
Distributed Generation - Peak	2019	1	2	1,777	1.05	1.00	1,866	8.23	18.52	9,961	9,880
Battery Storage	2018	30	1	2,067	1.05	1.00	2,170	7.12	35.60	N/A	N/A
Biomass	2021	50	4	3,584	1.07	1.00	3,837	5.58	112.15	13,500	13,500
Geothermal[8,9]	2021	50	4	2,615	1.05	1.00	2,746	0.00	119.87	9,271	9,271
MSW - Landfill Gas	2020	50	3	8,170	1.07	1.00	8,742	9.29	417.02	18,000	18,000
Conventional Hydropower[9]	2021	500	4	2,634	1.10	1.00	2,898	1.33	40.05	9,271	9,271
Wind	2020	100	3	1,548	1.07	1.00	1,657	0.00	47.47	9,271	9,271
Wind Offshore[8]	2021	400	4	4,694	1.10	1.25	6,454	0.00	78.56	9,271	9,271
Solar Thermal[8]	2020	100	3	3,952	1.07	1.00	4,228	0.00	71.41	9,271	9,271
Solar PV - tracking[8,11]	2019	150	2	2,004	1.05	1.00	2,105	0.00	22.02	9,271	9,271
Solar PV - fixed tilt[8,11]	2019	150	2	1,763	1.05	1.00	1,851	0.00	22.02	9,271	9,271

AEP Ohio also assumes fuel costs for natural gas and coal that are unreasonably high and inconsistent with EIA forecasts. In the 2018 Annual Energy Outlook, EIA provides its reference case forecast for energy prices.[18] The EIA forecast for natural gas and coal prices are materially below the levelized prices assumed by AEP Ohio in its analysis.[19]

[18] https://www.eia.gov/outlooks/aeo/pdf/appa.pdf

[19] The EIA prices are FOB mine for coal and Henry Hub for natural gas, making then not exactly comparable. The transportation costs for coal are not that significant given the proximity of Northern Appalachia coal, the likely coal despite the representation that the plant would be PRB sources. The Marcellus shale gas, which is the likely source of natural gas, is produced locally and currently trades at a negative basis differential to Henry Hub.

Table A1. Total energy supply, disposition, and price summary (continued)
(quadrillion Btu per year, unless otherwise noted)

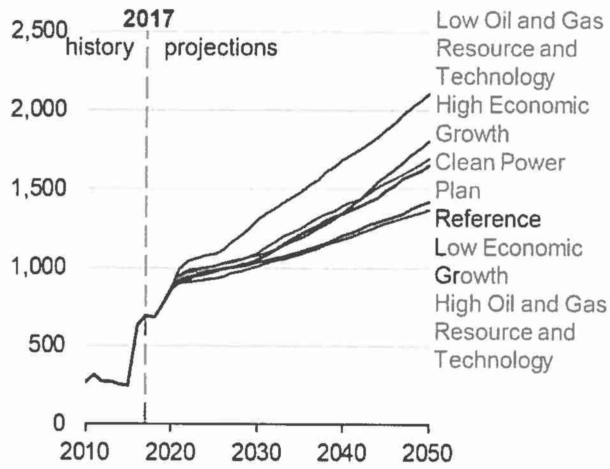
Supply, disposition, and prices	Reference case							Annual growth 2017-2050 (percent)
	2016	2017	2025	2030	2035	2040	2050	
Prices (nominal dollars per unit)								
Crude oil spot prices (dollars per barrel)								
Brent	44	52	104	125	150	179	244	4.8%
West Texas Intermediate	43	50	100	120	143	171	235	4.8%
Natural gas at Henry Hub (dollars per million Btu)	2.53	3.05	4.93	5.75	6.41	7.59	10.78	3.9%
Coal (dollars per ton)								
at the minemouth[14]	32.4	32.9	41.2	47.3	55.2	65.3	85.5	2.9%
Coal (dollars per million Btu)								
at the minemouth[14]	1.62	1.63	2.05	2.36	2.74	3.22	4.23	2.9%
Average end-use[15]	2.29	2.28	2.94	3.31	3.77	4.33	5.65	2.8%
Average electricity (cents per kilowatthour)	10.3	10.6	13.5	15.2	16.9	18.9	23.6	2.5%

Most importantly, AEP Ohio does not consider the risk to ratepayers associated with committing to a 20-year solar REPA now when all indications are that solar costs are likely to decline thereby creating a disconnect between current solar REPA prices and future market prices for solar or a solar REPA. This is similar to what apparently occurred with the wind PPA's AEP Ohio entered into as AEP Ohio ratepayers pay the higher wind REC prices through the AER even if REC prices drop.[20]

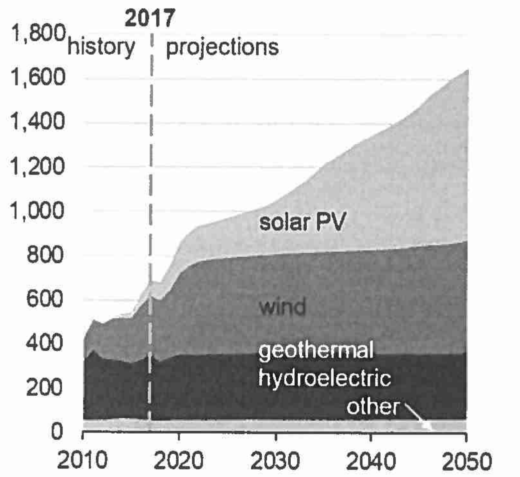
In the 2018 AEO, EIA finds that renewables growth is substantial under all of the scenarios it considered. In the Reference Case, most of the renewables growth is in solar.[21]

[20] As noted above, AEP Ohio customers would pay through a nonbypassable rider the PPA prices. If the PPA price is above the power price, customers will pay a surcharge for the solar prices.
[21] https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf, pages 93 and 95

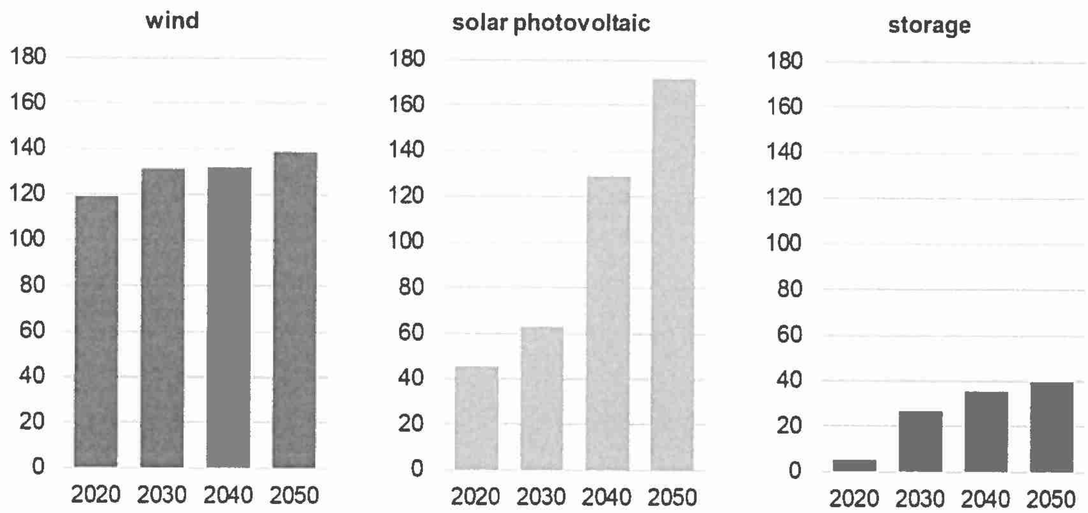
Total renewables generation, including end-use generation
billion kilowatthours



Renewable electricity generation, including end-use generation (Reference case)
billion kilowatthours



Utility-scale wind, solar, and storage operating capacity
gigawatts



Relevant statements in the 2018 Annual Energy Outlook include the following:

- "A combination of reductions in technology costs and implementation of policies that encourage the use of renewables at the state level (renewable portfolio standards) and at the federal level (production and investment tax credits) drives down the costs of renewables technologies (wind and solar photovoltaic), supporting their expanded adoption." [22]

[22] https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf, page 14

- "Wind and solar generation leads the growth in renewables generation throughout the projection, accounting for 64% of the total electric generation growth in the Reference case through 2050. With a continued (but reduced) tax credit and declining capital costs, solar capacity continues to grow throughout the projection period, while tax credits that phase out for plants entering service through 2024 provide incentives for new wind capacity in the near term."[23]
- "The capability to model two distinct solar photovoltaic (PV) technologies was added to better account for the cost and value trade-offs between fixed-tilt and tracking-solar technologies. Both technologies have achieved significant market share as PV installations have increased."[24]
- "Although the commercial solar investment tax credits (ITC) are reduced and the ITC for residential-owned systems expires, the growth in solar PV capacity continues through 2050 for both the utility-scale and small-scale applications."[25]

This last statement regarding the impact of the ITC is directly in conflict with AEP Ohio's position that the commitment for solar should be made immediately in order to take full advantage of the tax credits while they are still available.[26] AEP Ohio does not consider the advantage of lower solar costs by deferring the commitments. EIA shows considerable solar development with the reduced ITC because of declining costs.

AEP Ohio bolsters the economics for the renewables projects with what it refers to as AEP Ohio Impact. The AEP Ohio benefits are the "specific net impact to AEP Ohio and its customers ("AEP Ohio Impact') from adding … generic renewable resources."[27] The calculation of these benefits suffer from some of the same problems identified for the calculation of the PJM Impact. In addition, these benefits, like the PJM benefits are well within the margin of error, as shown in Exhibit ESM-3.

[23] https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf, page 20
[24] https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf, page 38
[25] https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf, page 100
[26] Direct Testimony of Company Witness Allen, Case 18-501, Page 14, Lines 2-3.
[27] Case No. 18-501-EL-FOR, Direct Testimony of John F. Torpey on behalf of Ohio Power Company, Page 5.

Exhibit ESM-3. NPV ASSUMED FOR RENEWABLES PROJECTS[28]

	Total NPV (Million $)	Percent of NPV	Cumulative Percent of NPV
PJM Impact	31	0.13%	0.13%
AEP Ohio Impact Solar	88	0.36%	0.49%
AEP Ohio Impact Wind	54	0.22%	0.71%

Further, the AEP Ohio Impact benefits for the solar projects are actually negative, i.e. the costs are higher, in the first four years of solar operation, with the generic solar plants as shown in Table 5 of Exhibit JFT-1. It is only because of the rapid increase in the avoided energy costs do the benefits turn positive. This is a serious concern and speaks to whether the projects should be deferred until there is more certainty as to future power prices and long-term solar costs.

Table 5. Generic Solar REPA Benefits

Net Cost of Energy
Generic Solar (400 MW)
2021 - 2040

A	B	C	D	E	F	G	H	I	J	K	L	M	N
		REPA Cost					Avoided Energy Cost		Avoided Capacity Cost				
Year	Present Value Factor	Capacity (Nameplate)	Solar Energy	Capacity Factor	Solar Energy Cost	Solar Total Cost	Solar Energy Priced at Market	Avoided Cost of Energy	Capacity Price	Solar Capacity Credit	Solar Capacity Credit Value	Total Change In Net Revenue Requirement	Net Cost of Energy
		(MW)	(GWh)	(%)	($/MWh)	($M)	($/MWh)	($M)	($/MW-Day)	(MW)	($M)	($M)	($/MWh)
2021	0.9217	400	813.9	23.2%	45.00	36.6	37.8	(30.8)	50.8	76.0	(1.4)	4.4	5.46
2022	0.8495	400	809.9	23.1%	45.00	36.4	39.2	(31.7)	30.1	76.0	(0.8)	3.9	4.77
2023	0.7829	400	805.8	23.0%	45.00	36.3	40.5	(32.7)	44.2	76.0	(1.2)	2.4	2.95
2024	0.7216	400	803.3	22.9%	45.00	36.2	41.8	(33.6)	58.7	76.0	(1.6)	0.9	1.18
2025	0.6650	400	797.8	22.8%	45.00	35.9	43.0	(34.3)	73.6	76.0	(2.0)	(0.5)	(0.60)
2026	0.6129	400	793.8	22.7%	45.00	35.7	44.0	(34.9)	88.9	76.0	(2.5)	(1.7)	(2.09)
2027	0.5649	400	789.8	22.5%	45.00	35.5	44.6	(35.2)	104.7	76.0	(2.9)	(2.6)	(3.29)
2028	0.5207	400	787.4	22.4%	45.00	35.4	55.6	(43.8)	120.9	76.0	(3.4)	(11.7)	(14.86)
2029	0.4799	400	781.9	22.3%	45.00	35.2	57.2	(44.7)	137.6	76.0	(3.8)	(13.3)	(17.04)
2030	0.4423	400	778.0	22.2%	45.00	35.0	60.7	(47.2)	154.8	76.0	(4.3)	(16.5)	(21.23)
2031	0.4076	400	774.1	22.1%	45.00	34.8	62.7	(48.6)	172.2	76.0	(4.8)	(18.5)	(23.90)
2032	0.3757	400	771.8	22.0%	45.00	34.7	64.9	(50.1)	190.1	76.0	(5.3)	(20.6)	(26.69)
2033	0.3463	400	766.4	21.9%	45.00	34.5	66.5	(51.0)	208.5	76.0	(5.8)	(22.3)	(29.09)
2034	0.3191	400	762.6	21.8%	45.00	34.3	68.1	(52.0)	227.3	76.0	(6.3)	(24.0)	(31.44)
2035	0.2941	400	758.8	21.7%	45.00	34.1	70.8	(53.7)	246.5	76.0	(6.8)	(26.4)	(34.83)
2036	0.2711	400	756.5	21.5%	45.00	34.0	72.2	(54.6)	266.3	76.0	(7.4)	(28.0)	(36.99)
2037	0.2499	400	751.2	21.4%	45.00	33.8	74.2	(55.7)	286.5	76.0	(7.9)	(29.9)	(39.78)
2038	0.2303	400	747.4	21.3%	45.00	33.6	78.0	(58.3)	307.1	76.0	(8.5)	(33.2)	(44.48)
2039	0.2122	400	743.7	21.2%	45.00	33.5	78.1	(58.1)	328.6	76.0	(9.1)	(33.7)	(45.34)
2040	0.1956	400	741.4	21.1%	45.00	33.4	80.7	(59.8)	350.6	76.0	(9.7)	(36.2)	(48.77)
Present Worth	9.4633					335.1		(389.2)			(33.9)	(88.0)	
Levelized			786.9	22.4%	45.00	35.4	52.3	(41.1)	129.0	76.0	(3.6)	(9.3)	(11.82)

[28] Case No. 18-501-EL-FOR, Direct Testimony of John F. Torpey on behalf of Ohio Power Company, Page 6.

AEP Ohio is proposing to be paid a debt equivalency cost as part of the PPAs which it would recover through the RGR. According to Direct Testimony of Company Witness Allen in Case 18-1392, the debt equivalency payment would be a payment to offset the cost, i.e., increased financial risk to bond holders, that would occur as a result of being a counter-party in each REPA. AEP Ohio has proposed specific and significant payments of $4.3 million per year related to Highland and $1.36 million per year related to Willowbrook. The analysis does not appear to include the proposed debt equivalency cost.

The Settlement Agreement which outlines in great detail the plan for the recovery of costs for the renewable projects contemplated for the RGR makes no mention of a Debt Equivalency Payment.[29] Further, this is not a customary payment. When asked, AEP Ohio did not identify any other utility which is receiving a debt equivalency payment, or its equivalent.[30] From my experience, there is no uniformity within the industry as to whether debt equivalency payments should be provided or how they should be calculated. In a current rate case in Michigan, the *regulated* utility has asked for a Financial Compensation Mechanism (FMC) for new PPAs in part to compensate for lost earnings when it chooses to enter into a PPA as opposed to add capacity through a self-build. The FMC is being hotly contested and the Michigan Commission has not yet ruled.[31] As AEP Ohio is not regulated, it is unclear this rationale makes sense as there is no self-build alternative. Further, AEP Ohio agreed to the PPA concept without the debt equivalency payment in the Settlement Agreement and there is not basis to make this change. Finally, it could be argued that AEP Ohio's compensation was its right to buy up to 50 percent of each project. The fact that AEP Ohio has reportedly declined to exercise this option does not negate the existence or value of this option.

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[29] The fact that AEP Ohio is requesting this payment (as opposed to calculating it) confirms that it was not identified in the Settlement Agreement.

[30] The OCA asked in a DR for the names of utilities which receive a debt equivalency payment. The OCA was referred to the response to OCC-RFD-01-007 and the testimonies of Fetter and Allen. One of the reports provided to OCC was 10 years old and included some examples which were not on point.

[31] https://mi-psc.force.com/s/case/500t0000009haqBAAQ/in-the-matter-of-the-application-of-consumers-energy-company-for-approval-of-its-integrated-resource-plan-pursuant-to-mcl-4606t-and-for-other-relief

In California, the Commission published a report in 2017 which explored the issue of debt equivalency. [32] The report noted that the Commission had not adopted a "comprehensive policy" on the matter. One important takeaway from this report is that all credit agencies do not impute debt related to PPA's in the same manner and the Commission needs to reflect this disparity in its related decisions. "The Commission's approach in Cost of Capital proceedings is partly based on the understanding that S&P always imputes debt but Fitch and Moody's sometimes do not and that S&P methodology should not be over-weighted versus Moody's and Fitch approach. Moody's, in particular, conducts qualitative assessment of PPA risk. Moody's determine the degree to which PPA effect a company's financial flexibility by a qualitative assessment of the inherent risk. Similarly Fitch does not always assign Debt Equivalency to PPA. More specifically Fitch does not assign Debt Equivalency when there is a high probability of cost recovery."

Finally, there appears to be inadequate consideration of the accelerated retirements of existing coal plants and the impact on system reliability. The analysis presumes a level of retirements (coal and nuclear) which do not necessarily have to proceed and may provide lower power prices and significant local benefits even if only for limited life extension.

In July 2018, EVA prepared an analysis of the Impact of Coal Plant Retirements on the U.S. Power Markets – PJM Interconnection Case Study, which is provided in Attachment ESM-3. While the study focused on the three First Energy merchant plants, the following conclusions are relevant to AEP Ohio ratepayers.

- The cost of power in the PJM market is expected to increase significantly as a result of the closures.

32 http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/PPD_Work/PPD_Work_Products_(2014_forward)/PPD%20-%20Intro%20to%20Debt%20Equivalency(1).pdf

- The coal plants are the primary source of resilience for the PJM 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 PJM 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.

The North American Electric Reliability Corporation (NERC) issued a Special Reliability Assessment of Generation Retirement Scenario on December 13, 2018.[33] Relevant conclusions include:

- The changing resource mix alters the operating characteristics and constraints of the Bulk Power System, and these changing characteristics must be well understood and incorporated into planning to assure continued reliability.

- Managing generator retirements and the transition to replacement resources is a cmplex process that requires close coordination between transmission and resource planners,

[33] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Retirements_Report_2018_Final.pdf

system and market operators , and state, provincial, and federal regulators. Accelerated retirements – or retirements that occur sooner than expected and are not yet incorporated into planning – can create challenges for this coordination, particular when multiple units request to retire over the same period.

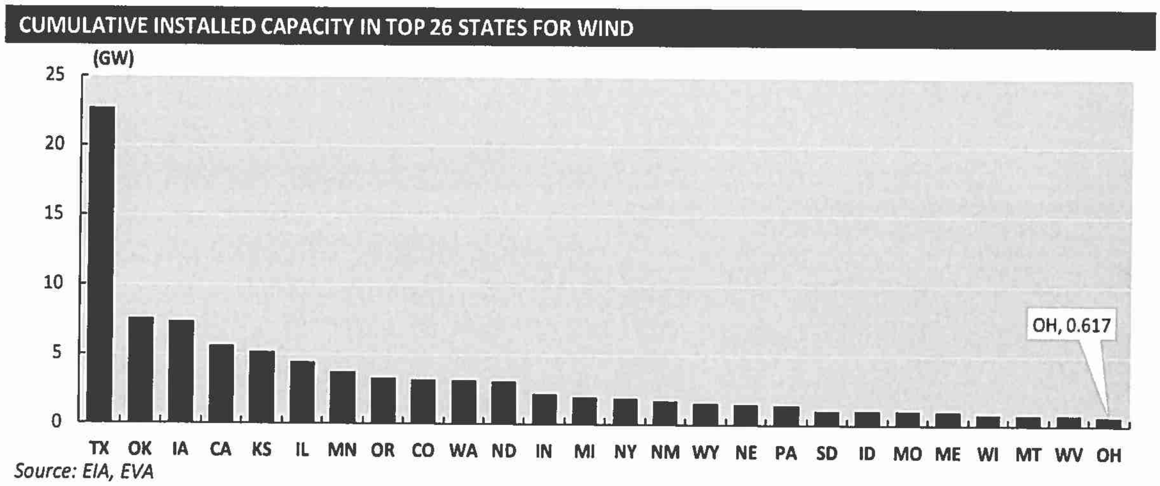
- The key conclusion is that generator retirements are occurring, disproportionately affecting large baseload, solid-fuel generation (coal and nuclear). If these retirements happen faster than the system can response with replacement generation, including any necessary transmission facilities or replacement fuel infrastructure, significant reliability problems could occur.

Since the original Settlement Agreement, there has been additional accelerated retirements announced in PJM that affect system reliability and costs that may not have been considered.

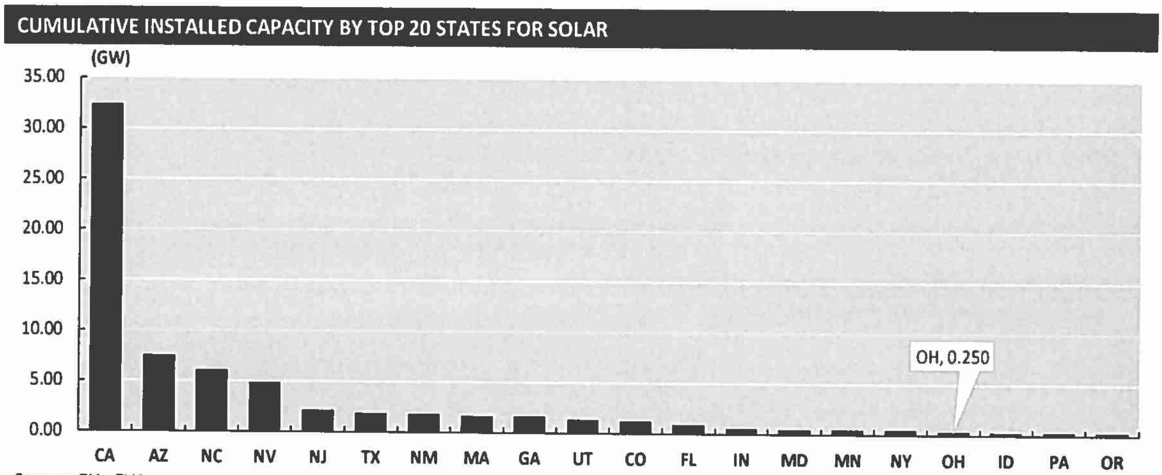
(3) Location of Projects in the State of Ohio

As of the end of 2017, Ohio does not rank high as a renewables generator, wind or solar. Ohio ranks 26th with respect to wind, accounting for about 0.6 percent of installed wind capacity. Ohio ranks 20th with respect to solar, accounting for about 0.4 percent of installed capacity. As shown in Exhibit ESM-4, Texas has the largest wind resources with over 25 percent of installed capacity and California has the largest solar resources with almost half of the installed capacity.

Exhibit ESM-4. CUMULATIVE INSTALLED RENEWABLE CAPCITY



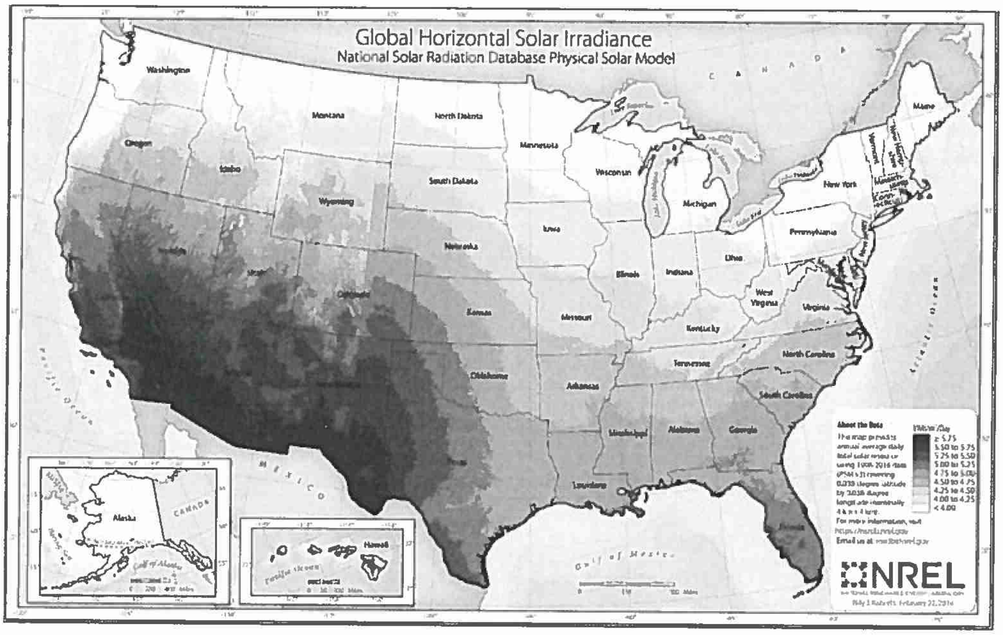
Source: EIA, EVA



Source: EIA, EVA

While policy has dictated some of the distribution of wind and solar, not all states have the same renewable resources and, therefore, potential. As shown in Exhibit ESM-5, solar resources in Ohio are relatively poor compared to other states. Solar costs are related to resource potential.

Exhibit ESM-5. Solar Resource Map[34]



The aforementioned Alternative Energy Portfolio Standard recognized the dearth of solar resources through the benchmark requirements. The initial benchmark requirements, which are shown in Exhibit ESM-6 set the minimum solar levels to a small fraction of the total renewable energy benchmark. Under the original renewable energy benchmark requirements, no more than 50 percent of the benchmark could be satisfied out of state. The original benchmark requirements also required an additional 12.5 percent by 2025 (with no interim targets) through advanced and/or renewable energy resources.

[34] NREL.gov. Solar Resource Maps. Direct Normal Solar Irradiance 1998-2016. https://www.nrel.gov/gis/assets/pdfs/solar_dni_2018_01.pdf

Exhibit ESM-6. Original Renewable Energy Benchmark Requirements

Year	Renewable Energy	Minimum Solar
2009	0.25%	0.00%
2010	0.50%	0.01%
2011	1.00%	0.03%
2012	1.50%	0.06%
2013	2.00%	0.09%
2014	2.50%	0.12%
2015	3.50%	0.15%
2016	4.50%	0.18%
2017	5.50%	0.22%
2018	6.50%	0.26%
2019	7.50%	0.30%
2020	8.50%	0.34%
2021	9.50%	0.38%
2022	10.50%	0.42%
2023	11.50%	0.46%
2024	12.50%	0.50%

In 2014, Senate Bill 310 among other things placed a two-year freeze on the renewable energy benchmarks, eliminated the requirement that at least 50 percent of the renewable energy resource had to be sourced in-state, and eliminated the 12.5 percent benchmark achieved through advanced and/or renewable energy resources.

The elimination of the in-state solar requirement reflected the higher costs associated with the in-state procurement. As noted in the Public Version of the 2015 Management/Performance and Financial Audits of the FAC of the Ohio Power Company, "(t)he biggest impact (of Senate Bill 310) may be on Ohio in-state solar REC's which have historically been the highest per unit cost component of the REC portfolio."[35,36]

While it may be desirable to have in-state solar, it is far from clear whether the derivative benefits of in-state solar outweigh its higher costs and the associated impact on electricity prices. Apparently, the State Legislature and the Governor did not think so when the

[35] https://dis.puc.state.oh.us/TiffToPDf/A1001001A15L01A81830H02954.pdf, https://dis.puc.state.oh.us/TiffToPDf/A1001001A15L01A81833C02956.pdf, https://dis.puc.state.oh.us/TiffToPDf/A1001001A15L01A81833H02958.pdf (Page 7-4)

[36] The Management/Performance and Financial Audits of the AEP AER are underway. After two delays, the audit report is now scheduled to be docketed in mid-January.

Renewable Energy Benchmark Requirements were amended in 2014 to eliminate the in-state requirements.

AEP Ohio quantified the employment benefits associated with an in-state plant but did not quantify costs associated with higher electricity prices. As the RFP was limited to in-state sources, the higher costs of an in-state plant cannot be quantified. [37]

In some jurisdiction where solar is not logically competitive, a superior alternative to a forced purchase through a nonbypassable rider is through a voluntary green energy program that allows customers to select potentially higher resource costs because of their environmental profile. The voluntary solar programs, often referred to as Community Solar, provide access to solar energy for interested parties. According to the Solar Energy Industries Association[38], 42 states have at least one community solar project on line. Current Community Solar capacity is estimated to be 1.9 gigawatts (GW); 3.0 GW are expected to be added in the next few years. While some Community Solar projects are local initiatives, others are utility- sponsored.

A voluntary Community Solar project in which customers elect to participate even if their participation requires them to pay more for their electricity is a much better vehicle to determine customer need (interest) than the poorly designed Navigant survey.

(4) Dedication of Solar Plants to AEP Ohio Customers

The Opinion and Order states that AEP Ohio will be the buyer under a long-term PPA for each project including all capacity, energy, ancillaries, and renewable energy credits produced by the project. Capacity, energy, and ancillary services for all projects will be liquidated into the PJM markets with resulting revenues being credited to retail customers. Renewable energy credits not reserved for compliance will be liquidated into the markets

[37] The RFP limitation to in-state sources precluded the appropriate evaluation of the cost containment such plants would provide.
[38] https://www.seia.org/initiatives/community-solar

with resulting revenues being credited to retail customers. Therefore, the structure of the RGR specifically precludes the output of the plants associated with the PPA being dedicated to AEP Ohio customers.

(5) Customer Preference

AEP Ohio in its determination of need is reliant on a survey it engaged Navigant to conduct. The study was commissioned to analyze business and residential customers attitudes regarding renewable energy generation in Ohio. AEP Ohio represents that Navigant's report demonstrates that AEP Ohio customers are supportive of competitively-priced Ohio-generated renewable energy and thereby confirms the needs for the proposed projects. More relevant, however, is the Navigant survey shows that Ohio customers care more about renewable energy then in-state renewable energy[39] and by and large they care more about maintaining current bill amounts than having AEP Ohio invest in renewables.[40]

As in most surveys, the responses of the survey are tied to the representativeness of the survey participants and how the questions are phrased.

With respect to the representativeness of the survey, there is no indication that Navigant or AEP Ohio performed the statistical analysis necessary to confirm the respondents were a representative sample of the AEP Ohio service area. As the survey was conducted via email, a significant share of the population was excluded as customers for which no email addresses were available were not contacted. AEP Ohio indicated that email addresses were not available for 38 percent of non-PIPP residential accounts, 43 percent of PIPP residential accounts and 65 percent of small C&I accounts.[41] The omission of significant segments of the population limits the conclusions that can be drawn from the responses that were provided.

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[39] Navigant Study, Figures 6 and 8
[40] Navigant Study, Figure 12
[41] Company Responses to OCC-INT-12-131.

Many of the questions in the survey produced what can best be called neutral responses. For example, the majority of large Commercial and Industrial (C&I) customers which responded to the survey (29 out of 34) "indicated they prefer that a portion of their renewable supply be based on local/regional projects in Ohio, assuming no significant difference in price." Small C&I customers agreed that "renewables should be used when cost-effective". The second most common neutral response from both Residential Non-PIPP customers and Residential PIPP customers was the same. Not asked was whether customers wanted to take a 20 year risk that the price under a solar PPA today would be lower in cost 10 years out given the expected decline in solar costs that the U.S. government is forecasting.

Said differently, it would have been a surprise if the survey concluded that AEP Ohio customers were not supportive of competitively-price Ohio renewable energy.
The real question is, which the Navigant survey did not adequately assess, what premium customers are willing to pay to support renewable energy development in Ohio given the distinct possibility if not the likelihood that the 20 year PPA will be out of the money for most (if not all) of its term.

Other jurisdictions have faced this very question. In Alaska, the Anchorage utility, Chugach, is sponsoring a Community Solar project in response to customer interest in renewables. The Community Solar project is voluntary and commitment to it is likely to result in an increase in electricity costs. Chugach engaged 3Degrees, a national consulting firm with specific expertise in renewable energy in part to address this question. 3Degrees found that in general of the respondents indicating a willingness to pay more for renewable, only three percent are actually willing to see an increase in their bills.[42] As a result, Chugach sized its Community Solar project to reflect the expected rate of participation.

To the extent that any conclusions can be drawn from the Navigant survey it is this. Customers support the development of renewables in Ohio if they are cost-competitive.

[42] http://rca.alaska.gov/RCAWeb/ViewFile.aspx?id=87056b6a-1ffb-4523-8e70-f1325b44815a, page 2

Given that AEP Ohio has not demonstrated that these projects are cost-effective, need for these projects has not been established.

A final point relates to AEP Ohio's persistent representation that companies either in Ohio or companies that have a prospective interest in locating in Ohio have a preference for renewable energy. As with other customer groups, this is only likely to be true if the renewable prices are competitive. More importantly, the Settlement agreement contemplates bilateral PPAs whose output would be purchased by retail customers. Therefore, that PPA option is available to the extent there is individual customer interest in renewable energy in Ohio,

V. CHANGES IN THE RENEWABLE GENERATION MARKET

Q. PLEASE SUMMARIZE THE CHANGES IN THE SOLAR ENERGY MARKET.

A. There has been rapid growth in renewable energy capacity in the U.S. due to strong policy support at both the state and federal level. While many of those policies are still in place and remain important, the rapid rate of cost declines—especially for wind and solar photovoltaic (PV)—have made renewable energy projects increasingly more competitive. The bulk of renewable energy development has been concentrated in states offering some combination of strong policy support **and high-quality resources**.

More than six GW of utility scale solar was added to the grid in 2017. Utility scale solar capacity now totals 24.8 GW and has increased nearly nine-fold since 2012. Residential and Commercial PV also grew significantly in 2017. Increasing by 2.2 and 2.1 GW respectively—there is now roughly 20 GW of both residential and commercial PV capacity in the United States.[43]

While the solar footprint remains modest, future growth is expected. Driven by the ITC and rapidly falling costs, a large amount of capacity is expected to be added in the short term, growing by an average compound average growth rate (CAGR) of 15 percent year over year and reaching about 55 GW of total capacity by 2022.[44] While activity will slow once the ITC for residential and commercial expires in 2022 (unless it is extended), the same is not believed to be true for utility-scale solar which continues to enjoy an ITC, albeit somewhat lower. My company forecasts total solar capacity to reach more than 150 GW by 2040.

[43] https://emp.lbl.gov/utility-scale-solar/
[44] EVA FUELCAST 2018

Q. ARE REGULATED UTILITIES EMBRACING RENEWABLES FOR FUTURE CAPACITY NEEDS?

A. Yes. All recent regulated utility Integrated Resource Plans of which I am aware include some renewable energy projects. What is changing is the expansion of the renewable share of future generation. The 2018 Integrated Resource Plans of two midwestern regulated utilities (Consumers Energy and Northern Indiana Public Service Company) recently announced long-term plans to increase renewables having deemed renewables a lower cost alternative without renewable energy standards or scheduled subsidies.[45]

Q. WHAT IS THE IMPLICATION OF THIS CHANGE?

A. This changes reflects a conclusion that the economics of solar are compelling even with the lower ITC going forward and do not require special cost recovery mechanisms to incent.

Q. ARE MERCHANT GENERATORS DEVELOPING RENEWABLES PROJECTS?

A. Yes. Although PPAs are less common in an era of uncertain future power prices (particularly in California where only 30 percent of power producers are expected to utilize PPAs in the next five years[46]), merchant generators can develop renewable projects with a few specific business models. One such model is selling to aggregators, who are capable of getting better prices from utilities and/or wholesale markets. Recent evidence exists that merchant generators are able to move forward with projects in PJM by "just running off of RECs and wholesale revenues.[47]"

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, but I reserve the right to update if additional information becomes available.

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[45] https://www.con sumersenergy.com/community/sustainability/energy-mix/renewables/integrated-resource-plan; https://www.in.gov/iurc/files/2018%20NIPSCO%20IRP.pdf
[46] https://www.ge.com/power/transform/article.transform.articles.2017.jan.a-power-purchase-agreement-no
[47] https://www.utilitydive.com/news/pjm-significant-chunk-of-renewables-to-come-from-corporate-procurement/533411/

Attachment ESM-1

RESUME OF EMILY S. MEDINE

EDUCATIONAL BACKGROUND

M.P.A.	Woodrow Wilson School of Public and International Affairs, Princeton University, 1978
B.A.	Geography, Clark University, 1976 (magna cum laude, Phi Beta Kappa)

PROFESSIONAL EXPERIENCE

Current Position

Emily Medine, a Principal, has been with Energy Ventures Analysis since 1987. Her experience includes forecasting, integrated resource plans, bankruptcy support, market strategy development, fuel procurement audits, fuel procurement, acquisition and investment analyses, and strategic studies. She has also provided expert testimony to regulatory commissions and in arbitration and litigation proceedings. The types of projects in which she is involved are described below:

Integrated Resource Planning

Ms. Medine works with utilities and/or stakeholders on the development and evaluation of Integrated Resource Plans (IRP). Ms. Medine focuses on validation of all assumptions including fuel, emission allowances, carbon, and renewable energy credits (RECs).

Procurement

Ms. Medine develops and implements fuel procurement strategies for U.S. and foreign coal consumers. Fuel procurement assistance has ranged from determining an appropriate strategy to soliciting bids and negotiating purchase agreements. In the last five years, Ms. Medine has advised several international coal consumers of their fuel procurement activities. Ms. Medine continues to advise numerous U.S. and international coal consumers on their coal and petroleum coke procurements. In recent years, Ms. Medine has worked on natural gas and REC procurement evaluations.

Forecasting

Ms. Medine develops forecasts of U.S. and global solid fuel demand and prices for alternative coal types, coke and market segments. These forecasts are provided to individual clients and are documented in various FUELCAST/COALCAST reports.

Bankruptcy Support

Ms. Medine was an advisor to the Horizon Natural Resource companies which operated as a debtor-in-possession in the development of a plan to accomplish reclamation on all permits not sold and transferred as part of the plan of reorganization. For a period of 15 months, Ms. Medine served as Executive Vice President of Centennial Resources, Inc., a debtor-in-possession, as part of EVA's contract to manage this company post-petition. In this capacity, she managed the day-to-day operations of the company as well as serving as the liaison between the company, state and county regulatory agencies, the bankruptcy court, and the lenders. This assignment ended upon the filing of Centennial's plan of reorganization. Ms. Medine has also served as the advisor to secured lenders in another coal industry bankruptcy. In this capacity, she reviewed and developed independent financial forecasts and operating plans of the debtor-in-possession. Ms. Medine has also provided support to the Department of Justice on coal industry bankruptcies.

Acquisition and Investment

Ms. Medine was the agent for Lexington Coal Company in the sale of its assets in Indiana and Illinois. As part of this engagement, Ms. Medine was responsible for the sale of three mines to Peabody Energy. Ms. Medine also routinely evaluates the economics of potential projects or acquisitions for producers, developers, and industrials. For coal projects, this includes market and financial forecasts. In addition to the above, Ms. Medine has completed the sale of multiple mine assets. Ms. Medine was an advisor to and on the board of The Elk Horn Coal Company until its sale to Rhino Energy in June 2011.

Fuel and Power Purchase Procurement Audits

Ms. Medine manages and performs fuel procurement audits on behalf of regulatory commissions, utility management, and third-party interveners. She has performed over 25 audits of utilities regulated by the Public Utilities Commission of Ohio and testified in a number of proceedings. She also managed two major audits of the fuel procurement practices of PacifiCorp. Recent audits include Appalachian Power (2006, 2007, 2015, 2016, and 2018) and Monongahela Power (2007, 2015, 2016, and 2018) on behalf of the Consumer Advocate of the State of West Virginia, Tucson Electric Power on behalf of the Arizona Corporation Commission in 2007/2008 and 2012, AEP Ohio on behalf of the Ohio's Consumer Counsel, and AEP Ohio (2009, 2010, 2011, 2012, 2013 and 2014) and Dayton Power & Light (2010, 2011, 2012, 2013, 2014, and 2015) on behalf of the staff of the Public Utilities Commission of Ohio.

Market Strategy Development

Ms. Medine assists clients in the development of marketing strategies on behalf of fuel suppliers and transporters. She has helped to identify the high value markets and strategies for obtaining these accounts.

Expert Testimony and Presentations

Ms. Medine prepares analyses and testimony in support of clients involved in regulatory and legal proceedings. She provides testimony in commission hearings on a variety of issues. Ms. Medine regularly speaks at industry meetings.

Prior Experience

Prior to joining EVA, Ms. Medine held various positions at CONSOL including Assistant District Sales Manager – Chicago Sales Office and Strategic Studies Coordinator. Prior to CONSOL, Ms. Medine was a Project Manager at Energy and Environmental Analysis, Inc. where she directed two large government studies. For the Environmental Protection Agency, Ms. Medine directed an evaluation of the energy, environmental and economic impacts of New Source Performance Standards on Industrial Boilers. For the Department of Energy, Ms. Medine directed an evaluation of the financial impacts of requiring utilities with coal capable boilers to reconvert to coal. Ms. Medine worked as a Research Assistant at Brookhaven National Laboratory while she attended graduate school.

Attachment ESM-2

Alternative Energy Rider

S.B. 221 included an Alternative Energy Portfolio Standard (O.R.C. 4928.64-65) which required 25 percent of all kilowatt hours of electricity sold by electric distribution utilities and electric services companies to retail electric consumers to be obtained by "alternative energy sources" by 2025. Alternative energy sources are defined as "advanced energy resources" and "renewable energy resources" that satisfy the applicable placed in-service requirement. Alternative energy sources can also include new and existing customer-sited advanced and renewable energy resources that the customer commits to integrate into the utility's demand-response, energy efficiency, or peak demand reduction programs. The final rules implementing the Alternative Energy Portfolio Standard, which were issued December 10, 2009, included annual renewable targets with a stated solar percentage. The final rules required that at least 50 percent of the renewable energy must come from in-state facilities and the balance must come from facilities that can deliver into the state.

In May 2014, the Ohio General Assembly passed 2014 Sub. S.B. No. 310 ("SB 310"), which became effective on September 12, 2014. Pursuant to SB 310's passage, several provisions of the Ohio Revised Code, including those referenced above, were amended. These amendments to the renewable energy and advanced energy requirements of S.B. 310 included a freeze at 2014 levels in the benchmarks for 2015 and 2016, the elimination of the 12.5 percent alternative energy requirement, and the elimination of the use of in-state renewables to meet the renewable standards.

To ensure compliance with the alternative energy standards, utilities are required to file an annual report that documents how their compliance obligations are calculated and provides a listing of the REC certificate numbers that were surrendered as part of their compliance obligation. If the utility has failed to meet its requirements in any year and such under-compliance is deemed to have been avoidable, the utility will be assessed a monetary penalty referred to as the "alternative compliance payment ("ACP").

Utilities can obtain relief from certain requirements and avoid paying the ACP. A utility does not have to comply if it demonstrates that compliance with the portfolio standard is "reasonably expected" to increase generating costs by three percent or more. In addition, a utility can obtain relief through the force majeure provisions which state that the PUCO has the ability to waive compliance if the utility can demonstrate that sufficient renewable energy products were not available in the market place.

The PUCO publishes electric distribution utilities' AER rates on a quarterly basis.[48] The rates for the six electric distribution utilities are shown below for the last nine quarters. Ohio Power's rates were the highest in eight of the nine quarters and exceeded the simple average of all six utilities by 145 to 412 percent over this period.

	2016	**2017**				**2018**			
Reporting Company	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**	**Q3**	**Q4**
Cleveland Electric Illuminating	$ 0.14	$ 0.15	$ 0.06	$ 0.24	$ 0.43	$ 0.22	$ 0.43	$ 0.39	$ 0.40
Dayton Power & Light	$ 0.19	$ 0.19	$ 0.04	$ 0.07	$ (0.12)	$ 0.06	$ 0.06	$ 0.10	$ 0.10
Duke Energy - Ohio	$ 0.38	$ 0.33	$ 0.42	$ 0.23	$ 0.28	$ 0.44	$ 0.66	$ 0.08	$ 0.22
Ohio Edison Company	$ 0.11	$ 0.13	$ 0.07	$ 0.15	$ 0.32	$ 0.23	$ 0.47	$ 0.38	$ 0.38
Ohio Power Company	$ 0.79	$ 0.75	$ 1.53	$ 1.31	$ 0.56	$ 1.66	$ 2.07	$ 1.24	$ 0.54
Toledo Edison Company	$ 0.16	$ 0.23	$ 0.11	$ 0.20	$ 0.53	$ 0.43	$ 0.63	$ 0.51	$ 0.59
Average	$ 0.30	$ 0.30	$ 0.37	$ 0.37	$ 0.33	$ 0.51	$ 0.72	$ 0.45	$ 0.37
Ohio Power vs Average	**268%**	**253%**	**412%**	**357%**	**168%**	**328%**	**288%**	**276%**	**145%**

Source: PUCO Website, Renewable Portfolio Standard/Rate Impacts, Quarterly Filings

48 https://www.puco.ohio.gov/industry-information/industry-topics/ohioe28099s-renewable-and-advanced-energy-portfolio-standard/

Attachment ESM-3

JULY 2018

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

July 2018

ENERGY VENTURES ANALYSIS

Prepared by:

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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.

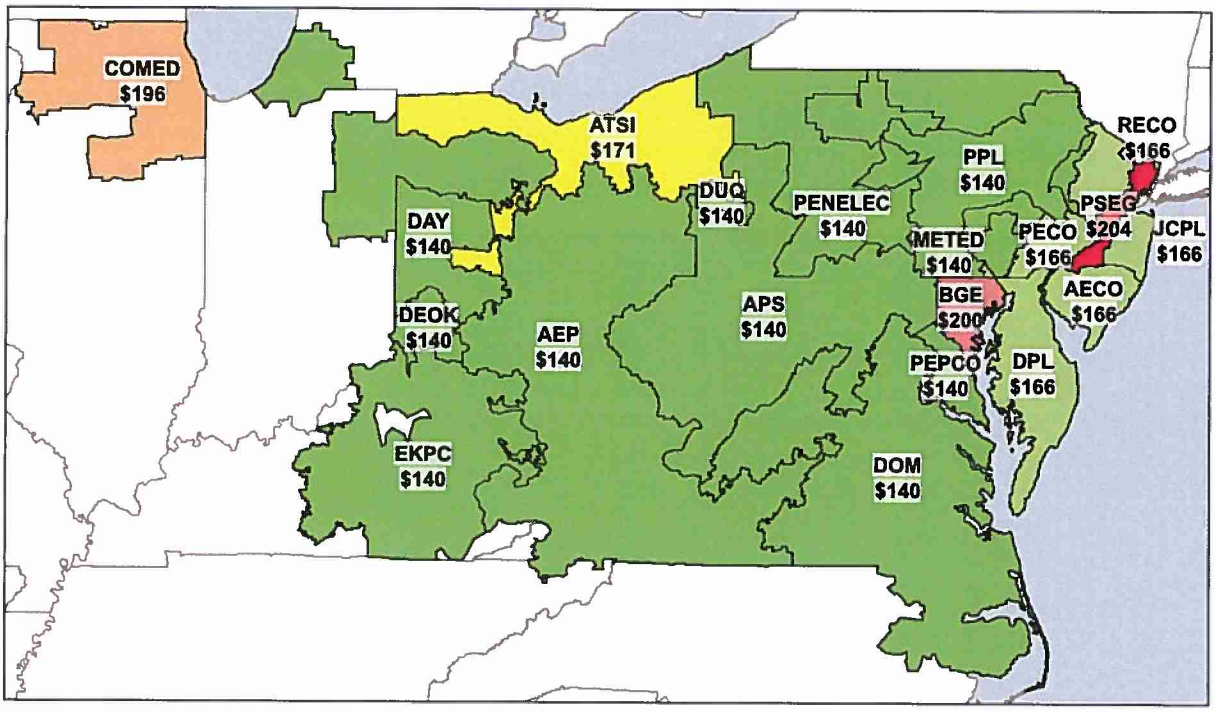
Impact of Closing the Coal Plants on PJM Capacity Costs

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.

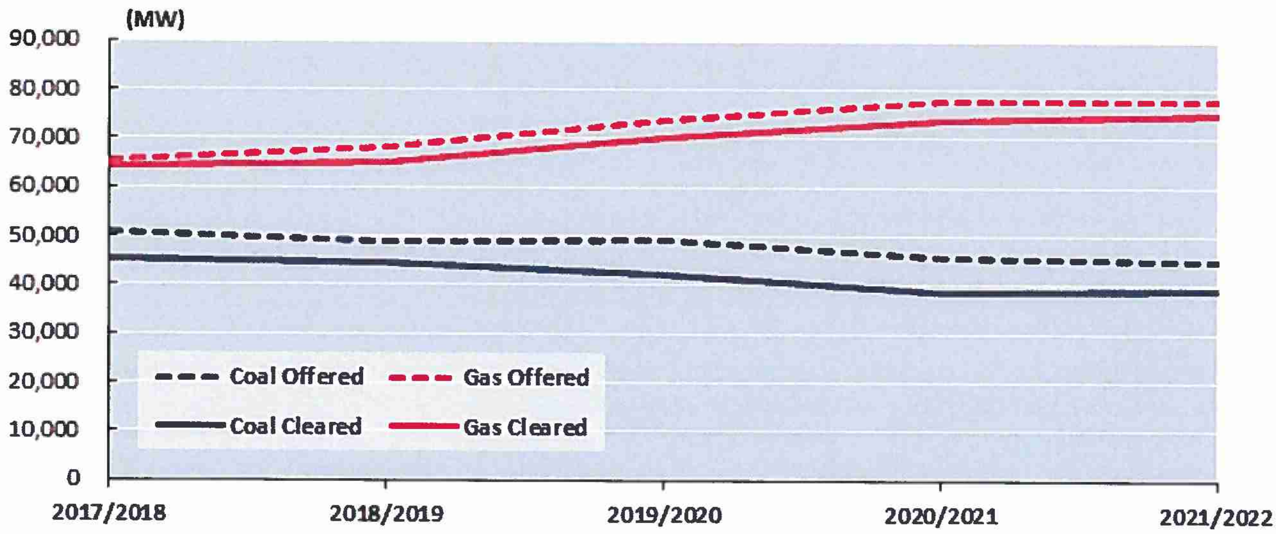
PJM's latest capacity auction was in May 2018 for capacity committed for the 12-month period June 2021 – May 2022 (2021/2022 BRA).

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			Resources	Cost Increase in 2021/22 BRA	
	2019/20	2020/21	2021/22	Cleared	From 2019/20	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.

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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]

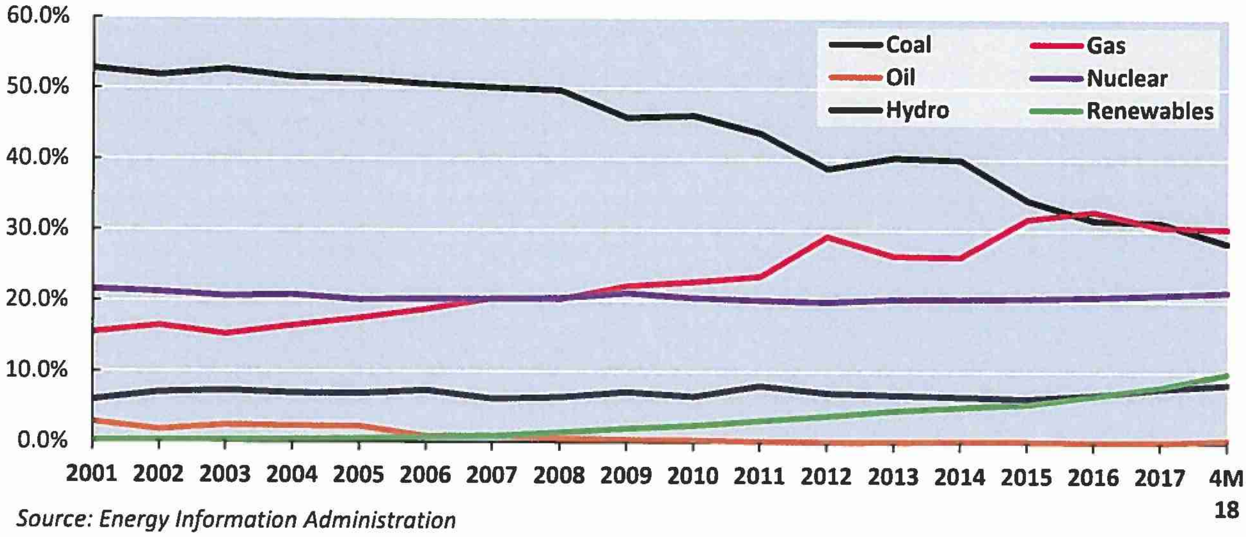
Increasing Reliance on Gas and Renewables is Jeopardizing Reliability

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.

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- 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			

Plant	Unit	State	MW	Retirement Date Year	Retirement Date 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**			

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Case No(s). 18-0501-EL-FOR, 18-1392-EL-RDR, 18-1393-EL-ATA

Summary: Testimony Direct Testimony of Emily S. Medine on Behalf of the Ohio Coal Association (OCA) electronically filed by John F Stock on behalf of Ohio Coal Association