PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

At a session of the PUBLIC SERVICE COMMISSION OF WEST VIRGINIA in the City of Charleston on the 30th day of May 2018.

CASE NO. 17-0894-E-PC

APPALACHIAN POWER COMPANY and
WHEELING POWER COMPANY, public utilities,
Petition for consent and approval of acquisition of wind facilities (Hardin Wind Facility, Hardin County, Ohio; and Beech Ridge II Wind Facility, Greenbrier County, WV).

COMMISSION ORDER

The Commission denies the Petition for Consent and Approval filed by Appalachian Power Company and Wheeling Power Company on July 5, 2017, for the acquisition of the Hardin Wind Facility and the Beech Ridge II Wind Facility.

BACKGROUND

On July 5, 2017, Appalachian Power Company (APCo) and Wheeling Power Company (WPCo) (collectively Companies) filed a Petition for Commission consent and approval for APCo to enter into certain transactions to acquire, after completion of construction, the Hardin wind generation facility (Hardin Wind Facility), that is under development in Hardin County, Ohio, and the Beech Ridge II wind generation facility (Beech Ridge II Wind Facility) that is under development in Greenbrier County, West Virginia (collectively Wind Facilities or Projects).[1] The Beech Ridge II facility is a 50 Mw wind project and the Hardin facility is a 175 Mw wind project.

The petitions to intervene filed by the Consumer Advocate Division (CAD) of the Commission and West Virginia Energy Users Group (WVEUG) were granted. Commission Order, September 8, 2017.

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1 The Commission notes that the Virginia State Corporation Commission (VSCC) recently denied an APCo request for a rate adjustment to recover Virginia's allocated share of costs for the same wind farms at issue in this case concluding that the purchase of the wind farms was not necessary for Virginia customers. VSCC Case No. PUR-2017-00031, Order entered April 2, 2018, (Reconsideration Denied, April 20, 2018).

On March 14 and 15, 2018, the Commission held an evidentiary hearing in this case.[2] Initial Briefs from the parties were filed on April 6, 2018, and Reply Briefs were filed on April 20, 2018.

On March 29, 2018, the Companies filed a letter informing the Commission of an offer from General Electric to upgrade the wind turbine generators at the Hardin Wind Facility. CAD and WVEUG opposed the filing of the letter. CAD Motion to Strike and/or Open the Record, March 30, 2018; WVEUG letter, April 2, 2018. The Commission granted the CAD Motion to Strike on April 12, 2018, and did not consider the Companies' March 29th letter in the decision in this case.

The Ratemaking Treatment of the Wind Facilities

If acquired, the Wind Facilities will be owned by APCo. The associated investment will be part of APCo's rate base and the associated operating expenses and taxes will be part of the Companies' base rate revenue requirements. As described by APCo:

> [R]evenue requirement for the Wind Facilities includes the following types of costs:
>
> 1) a return of (through depreciation) and a return on (using the capital structure and cost of equity described by Company witness Scalzo) APCo's capital investment in the Wind Facilities net of accumulated depreciation and accumulated deferred income taxes;
>
> 2) various operational and maintenance (O&M) expenses;
>
> 3) administrative and general (A&G) costs including salaries and benefits and property insurance; and
>
> 4) real and personal property taxes and employment taxes.
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> APCo's capital investment will consist principally of the acquisition price of the Wind Facilities but will also include any capitalizable costs incurred incidental to their acquisition.

Cos. Exh. AWA-D at 3.

APCo is requesting that cost recovery of the base rate revenue requirements of the Wind Facilities begin immediately with the closing of its purchase transaction rather than waiting for the next rate case after closing to include the revenue requirements into base

[2] In this Order, we will cite to the transcript as Tr. I (March 14th) and Tr. II (March 15th).

rates. APCo proposes that if the transaction is approved the Commission authorize a special surcharge to be included in rates upon closing of the purchase transaction. Because this surcharge will be based on projected costs, APCo is also requesting a true-up mechanism. APCo plans to practice deferral accounting by comparing the actual incurred costs associated with the Wind Facilities to the recovery of such costs through the approved surcharge. Net under-recoveries recorded as a regulatory asset or net over-recoveries recorded as a regulatory liability would, if approved by the Commission, be included for future recovery or refund, respectively, through the proposed true-up to actual costs in subsequent proceedings. Id. at 6-7.

The first-year revenue requirement of the Beech Ridge II Wind Facility is $6.1 million, or $2.5 million on a West Virginia jurisdictional basis. The first-year revenue requirement of the Hardin Wind Facility is a total of $18.2 million, or $7.6 million on a West Virginia jurisdictional basis. These revenue requirements are net of significant Federal Production Tax Credits (PTC) which are available only for the first ten years of the Wind Facilities twenty-five year life.

POSITION OF THE PARTIES

The Companies

Based on original estimates of revenue requirements of the Wind Facilities and the market cost of energy that would be purchased by the Companies without the energy from the Wind Facilities, the Companies projected that the Hardin Wind Facility had a total company positive net present value (NPV) to customers of $55.0 million and the Beech Ridge II Wind Facility had a positive NPV to customers of $21.4 million, when evaluated against the current Fundamentals Forecast before the sale of the renewable energy certificates (RECs)[3] is considered. Cos. Exh. JJS-D at 7.

The original cost estimates and comparisons to the market cost of purchased energy performed by the Companies were based on federal income tax rates in effect in 2017. The new Tax Cuts and Jobs Act of 2017 (TCJA) changed the cost analysis performed by the Companies, and ultimately the originally negotiated purchase price of the Wind Facilities. The effect of the TCJA increased the net revenue requirements on the projects because of a lower tax benefit from special wind project tax credits. To offset this increased revenue requirement, the project developer, Invenergy, offered certain price reductions that lowered the cost of the wind projects. Cos. Exh. JJS-SD at 1-2.

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[3] A renewable energy certificate, or REC (pronounced: rěk), is a market-based instrument that represents the property rights to the environmental, social and other non-power attributes of renewable electricity generation. RECs are issued when one megawatt-hour (MWh) of electricity is generated and delivered to the electricity grid from a renewable energy resource. RECs are the accepted legal instrument through which renewable energy generation and use claims are substantiated in the U.S. renewable energy market.

The Companies presented updated testimony that, due to the adjusted purchase price and the effect of the TCJA on revenue requirements, the Hardin Wind Facility revised total company positive net NPV to customers compared to the market dropped to $42.9 million and the Beech Ridge II Wind Facility positive NPV to customers also dropped to $14.8 million. These data were based on comparisons of the Wind Facilities' revenue requirements to a 2016 PJM Market Price forecast characterized by the Companies as their Market Fundamentals Forecast, which assumed increased market prices in the future due to potential carbon costs. The values were also based on the gross revenue requirements of the Wind Facilities, including the Federal Production Tax Credits (PTC) in years one through ten, but before a potential credit from the sale of RECs was considered. Monetizing the RECs associated with the Wind Facilities at an assumed selling price of $7 each for ten years would add $16.5 and $5.2 million in total company present value for Hardin and Beech Ridge, respectively. Cos. Exh. JJS-SR corrected during Evidentiary hearing at 3.

In addition to the projected NPV benefit as compared to market purchases, the Companies described other benefits that they believed justified the acquisition of the Wind Facilities. These benefits included:

1. The Wind Projects offer an opportunity to take full advantage of the PTC.

2. The exceptionally low cost of the power produced by the Wind Projects for their first ten years of operation.

3. The step-up in the Wind Projects' power costs after the first ten years with the cessation of the PTC benefits would coincide neatly with the expiration of the bulk of APCo's existing higher priced purchased power agreements for wind.

4. The bolstering of the level of wind power in the Companies' diversified mix of generation resources at a time when the level would otherwise drop precipitously.

5. The hedge that the Wind Projects offer not only against spikes in market energy prices but also against the prospects of future carbon regulation or other environmental regulations.

Staff, CAD and WVEUG

Staff and CAD opposed the acquisition of the Wind Projects. Their positions were generally consistent, arguing that APCo had no need for capacity to meet PJM Interconnection LLC (PJM) capacity requirements which apply to the summer months. They also argued that to meet energy requirements in the winter, the Companies could, and should, continue to rely on the PJM energy market. Using the revised revenue requirements for the Wind Facilities, based on the new tax rates and revised purchase price presented in the Companies revised data, Staff witness Short testified that his calculations, which included his view of likely lower projected PJM market prices, demonstrated that the Wind Projects would cost customers more than the PJM market alternative. The CAD, in its initial brief, urged that the Commission conclude, as has the VSCC, that when the record, as a whole, is considered, the Companies' projection of future PJM prices appears to be inflated. CAD stated that the alternative view of the PJM market presented by Staff showed that the Wind Facilities would cost West Virginia ratepayers more than the market alternative, and, therefore, the projects should be rejected by the Commission.

WVEUG witness Baron opposed the Hardin Project and expressed reservations about the Beech Ridge II Project. He considered the No Carbon case used by the Companies to be more reasonable, and testified:

> Based on Mr. Torpey's updated [No Carbon] analyses, the NPV economic benefit for the Beech Ridge II project is $3.0 million, and it is $6.7 million for the Hardin project. The original NPV economic benefits calculated by the Companies for these two projects were $9.6 million and $18.8 million, respectively. This represents a 69% reduction in NPV economic benefits for the Beech Ridge II project and a 65% reduction in Hardin benefits due to the tax law change.

WVEUG Exh. SJB-SD at 3.

Mr. Baron testified that based on Mr. Torpey's No Carbon case the Beech Ridge II project would become uneconomic if the actual PJM market energy prices were 3.9% lower than the AEP projection. He further testified that for the Hardin project, if the actual PJM energy prices were only 2.9% lower each year, the NPV benefits would be fully eliminated, and if the market prices were any lower, the project would be harmful to the Companies' customers. Mr. Baron concluded that he did not expressly support either acquisition. He opined, however, that the smaller Beech Ridge II acquisition would be less risky for ratepayers than the Hardin project. He further stated that because Beech Ridge II is located in West Virginia, to the extent the acquisition provides other marginal economic benefits, those benefits would inure to West Virginia (as compared to the Hardin project in Ohio).

WVEUG opposed the surcharge rate recovery mechanism requested by the Companies. Mr. Baron testified that the use of a surcharge mechanism does not permit the consideration of potential offsetting revenue requirement changes. He also objected to the shift of investment risks from shareholders to ratepayers. He concluded that WVEUG continues to recommend that these types of investment costs be recovered through base rates, rather than yet another surcharge. WVEUG Exh. SJB-D at 14.

DISCUSSION

Virginia State Corporation Commission (VSCC) Denial

The VSCC found that APCo did not prove a need for the capacity. In its case before the VSCC, APCo did not assert a capacity need, but did assert that the wind facilities are needed to provide a lower cost source of energy compared to purchases from PJM. The VSCC also held that APCo failed to establish that the wind facilities are needed to address an energy deficiency or that they would likely provide energy at a lower overall cost to customers. Appalachian Power Co., Commonwealth of Virginia State Corp. Comm'n., Case No. PUR-2017-00031, Final Order, April 2, 2018, at 4-5 (Reconsideration Denied, April 20, 2018).

The VSCC shares our concerns about the highly speculative nature of the Companies market price justification for owning the Wind Facilities. In its Order Denying Reconsideration, the VSCC wrote:

> In addition, APCO's claimed benefit of the facilities – avoiding higher-priced market purchases – is speculative, dependent upon fluctuating market prices for 25 years, while the increased cost for the facilities is not speculative but, rather, locked in to customers for those 25 years. Indeed, APCo narrowly focuses on the cost of the facilities over the first ten years of their service life, while the Commission properly considers the costs to customers over the full 25-year service life. This is particularly significant because the record reflects that the cost of these facilities and, thus, costs to customers, will significantly increase after the first ten years, when the Production Tax Credit ends.

VSCC, Order Denying Reconsideration, April 20, 2018, at 3 (citations omitted).[4]

The Virginia denial is persuasive and important not only because VSCC's reasons for denial mirror our concerns as discussed later in this order, but also because the Virginia denial creates a situation where the traditional allocation of the cost of APCo

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[4] In their Reply Brief, the Companies pointed out a reference in the VSCC denial Order to a new statute in Virginia, addressing wind and solar generation facilities. Specifically, the Companies noted the VSCC said: "Because this proceeding is legislative in nature and our determination is without prejudice, APCo may present new evidence in support of a new application to acquire these resources, with SB 966 applicable to any such application filed on or after July 1, 2018 [SB966] includes legislative predetermination that the construction and purchase of power generated from solar or wind generating facilities up to certain quantities is 'in the public interest' and the Commission is mandated to make such a finding in applicable cases." We note that there is no such mandate in West Virginia law and a VSCC public interest finding under such a mandate would not change the public interest test based on reasonableness, prudence and cost that is employed by this Commission and which has led to our disapproval of the transactions based on the record developed in this proceeding.

production facilities between jurisdictions cannot occur under the normal jurisdictional cost allocation model. Some alternative to the normal jurisdictional cost allocation, as yet unknown and unexplained by the Companies, would have to be considered by this Commission even if the VSCC allowed APCo to acquire the Wind Facilities as long as the Virginia ratepayers are shielded from the costs. Thus, even if this Commission found that the Companies' petition should be granted, the acquisition of the Wind Facilities could not occur without further proceedings in West Virginia to firm up cost allocation and probably in Virginia to address treating the facilities as non-jurisdictional to that state. Mr. Scalzo testified that the transactions require approval of both the Virginia and West Virginia Commissions. Cos. Exh. JJS-D at 4. The Companies have not explained how the VSCC denial would affect West Virginia ratepayers or if it is possible for the transactions to be completed.

Need

The need for capacity was a central issue in this case. The Companies admit that they have sufficient capacity to meet PJM requirements using the generation resources already under contract or owned by APCo and WPCo. Tr. II at 52-53 (Scalzo). The Companies, however, argue that they do not generate sufficient energy to serve their customers in the winter months. Id. APCo sells all of its generated energy into the PJM wholesale market and purchases all of its energy requirements from the same market. Tr. II at 32, 44 (Scalzo on cross-examination); WVEUG Exh. SJB-D at 7. There is no dispute that PJM incurs its own internal peak load in the summer months. PJM plans its supply resources to meet its summer peak demand and energy requirements and, therefore, has more than enough generating capability in the winter to make up for any shortfall between APCo's energy generation and its customer energy needs. Thus, because of the availability of an ample wholesale purchase option from the PJM energy market, the Companies do not need to own or bi-laterally contract for additional energy to meet their internal load requirements. Notwithstanding this lack of need for energy, the Companies argued that the proposed Wind Facilities transactions are a physical hedge against the purchase of energy in the winter months. All parties agreed that the Wind Facilities were a physical hedge against reliance on market purchases, but there is a dispute whether the Wind Facilities would provide the lowest priced reliable alternative for energy necessary to meet customer requirements.

Cost to Ratepayers

Mr. Scalzo testified for the Companies that the PTC would be sufficient to offset approximately forty-eight percent of the cost of the revenue requirements of the Wind Facilities for the first ten years, the time the PTC would be in effect. Cos. Exh. JJS-SD at 4. The revenue requirements of the Wind Facilities for years eleven through twenty-five are much higher because of the elimination of the PTC, and the benefit to ratepayers is less certain.

The low net cost to ratepayers in the first ten years due to the PTC creates a concern for fairness to future ratepayers who will be required to bear the higher costs in years eleven through twenty-five. We cannot close our eyes to the fact that the NPV cost benefits of these facilities, if they do exist, are heavily influenced by the low net cost in the first ten years. If lower net costs in the early years are offset by higher costs in later years, the often argued inter-generational problem raises its head.

The Commission is required by statute to appraise and balance the interest of current and future utility service customers. W. Va. Code §24-1-1(b). The benefits or costs calculated by the Companies and Staff have been presented to us as a twenty-five year Net Present Value number. To balance the interests of present customers, who receive all of the PTC benefits, against the interest of future customers who will receive no PTC benefits we should at least be aware of the NPV impacts in those two discrete periods. No party has presented evidence on those NPV values.

There may be no problem at all, or only a minor inter-generational issue, but we cannot know that, given the way the NPV data has been presented.

The Beech Ridge II Wind Facility has a West Virginia allocated (West Virginia Jurisdictional) base rate revenue requirement of approximately $2.4 million per year for the first ten years. For the following fifteen years, the Beech Ridge II West Virginia Jurisdictional base rate revenue requirement is approximately $3.9 million per year. The total West Virginia Jurisdictional base rate revenue requirement over the full twenty-five year life of Beech Ridge II is $83.2 million. The Hardin Wind Facility has a West Virginia Jurisdictional base rate revenue requirement of approximately $7.6 million per year for the first ten years and approximately $12.6 million per year for the following fifteen years, or a twenty-five total of $265.3 million. Over the entire twenty-five year life of both facilities the West Virginia Jurisdictional base rate revenue requirement of Beech Ridge II and Hardin totals $348.5 million.

If the Projects' revenue requirements are not allocated between West Virginia and Virginia, which is a possible scenario in light of the decision of the VSCC, the total revenue requirement cited above could be significantly higher for West Virginia ratepayers. The total base rate revenue requirement of the Wind Facilities over the first ten years would be $240.5 million without cost allocation between the two states. The total base rate revenue requirement for years eleven through twenty-five would be $599.1 million. Thus, the total unallocated base rate revenue requirement over the twenty-five year life of the Wind Facilities will be $839.6 million. Co. Exh. JJS-SD at JJS-S2 and JJS-S4.

All of these values are base rate revenue requirements before any offset that might be obtained from REC credits. The issue of REC credits received some attention in the record. Although all parties agreed that there was a potential for some level of REC credits, there was also some disagreement about the value of REC credits. The Companies originally presented cost data without REC credits, but did mention that the net costs of the Wind Facilities would be lower to the extent REC credits are sold. The Companies originally suggested that the value of REC credits could vary. In revised filings, the Companies assumed a $7 value for each REC credit during the first ten years of the Wind Facilites lives.

WVEUG witness Baron failed to consider REC credits in his analysis but indicated uncertainty about the value of REC credits.

> And the fact that in the Company's own analysis, it provided a range, which led me to conclude that the Company itself was not that confident in what those REC values would be over even a ten-year period . . . I would acknowledge that the RECs have value of some magnitude. I don't know what that is. I'm not sure that anybody does. It's certainly an uncertainty. But all else being equal, I certainly would agree it's greater than zero. And that it would add to the economic value of renewable resource like Beech Ridge II and Hardin.

Tr. I at 192 – 193.

Knowing that the total aggregate revenue requirement of the combined facilities is $839.6 million over twenty-five years, or even knowing the annual revenue requirement, does not provide sufficient detail to evaluate the reasonableness of the revenue requirements of the Wind Facilities. The cost per unit of output (per MWh) for direct comparisons with alternative sources of energy such as purchases from the PJM market is important. The Companies provided testimony that the average cost of the Wind Facilities, net of REC sales at $7 per REC, was $30 per MWh during the first ten years of operation. Exhibit JJS-S at 3 and 4. The Companies later refined that number to be $30.34 per MWh. Initial Brief at 24. Absent the REC credit, the average cost per MWh in the first ten years would be $37.34.

The Companies did not provide publicly the average revenue requirement per MWh for years eleven through twenty-five, but did provide the annual total revenue requirements for those years. There is no indication on the record that the output from the Wind Facilities will fluctuate from year to year, but we can derive the per MWh revenue requirements in those years using a ratio of annual revenue requirements to the first ten-year average applied to the $37.34 pre-REC-credit average revenue per MWh. The following Table shows the total annual dollar amount of revenue requirement for each facility from Co. Exh. JJS-SD at JJS-S2 and JJS-S4, the average revenue requirement over the first ten years as provided by the Companies, and the average revenue requirement in years eleven through twenty-five calculated as described above.

	Total Dollars Unallocated Revenue Requirement					Avg. Per MWh
Year	Beech Ridge II	Hardin	Total	Before $7 REC Credits		After $7 REC Credits
	Million $	Million $	Million $	Per MWh		Per MWh
1	6.0	18.2	24.2	$ 37.47	**(2) (3)**	$ 30.47
2	6.7	20.0	26.7	$ 41.34	**(2) (3)**	$ 34.34
3	6.3	18.8	25.1	$ 38.87	**(2) (3)**	$ 31.87
4	6.3	19.2	25.5	$ 39.49	**(2) (3)**	$ 32.49
5	5.8	18.1	23.9	$ 37.01	**(2) (3)**	$ 30.01
6	5.9	18.3	24.2	$ 37.47	**(2) (3)**	$ 30.47
7	5.9	18.3	24.2	$ 37.47	**(2) (3)**	$ 30.47
8	5.7	18.0	23.7	$ 36.70	**(2) (3)**	$ 29.70
9	5.3	16.8	22.1	$ 34.22	**(2) (3)**	$ 27.22
10	4.9	16.0	20.9	$ 32.36	**(2) (3)**	$ 25.36
10-Yr. Sub Total	58.8	181.7	240.5			
10-Yr. Annual Average	5.9	18.2	24.1	$ 37.24	**(1)**	$ 30.24
11	11.2	35.2	46.4	$ 71.85	**(2) (3)**	
12	11.0	34.7	45.7	$ 70.76	**(2) (3)**	
13	10.8	33.8	44.6	$ 69.06	**(2) (3)**	
14	10.5	32.5	43.0	$ 66.58	**(2) (3)**	
15	10.1	32.1	42.2	$ 65.34	**(2) (3)**	
16	9.9	31.3	41.2	$ 63.80	**(2) (3)**	
17	9.6	30.6	40.2	$ 62.25	**(2) (3)**	
18	9.3	30.2	39.5	$ 61.16	**(2) (3)**	
19	9.2	29.7	38.9	$ 60.23	**(2) (3)**	
20	9.0	29.5	38.5	$ 59.61	**(2) (3)**	
21	8.9	28.8	37.7	$ 58.38	**(2) (3)**	
22	8.6	28.1	36.7	$ 56.83	**(2) (3)**	
23	8.3	27.6	35.9	$ 55.59	**(2) (3)**	
24	8.1	27.0	35.1	$ 54.35	**(2) (3)**	
25	7.7	25.8	33.5	$ 51.87	**(2) (3)**	
15-Yr. Sub Total	142.2	456.9	599.1			
15-Yr. Annual Average	9.5	30.5	39.9	$ 61.84		

(1) From Companies' Original Brief.
(2) = (Current Year Cost ÷ 10-Year Average Cost) X $37.24
(3) This calculation does not use projected output or capacity factors of the Wind Facilities. The calculated rates per MWh may differ from the Companies' confidential projections to the extent that output and capacity factors fluctuate from year to year.

The total cost of the Wind Facilities will jump to approximately $71.85 per MWh before REC credits in the eleventh year. This number will gradually decline over the last fifteen years of the life of the Wind Facilities but will average nearly $62.00 per MWh.

These costs per MWh should be compared to reasonably projected PJM energy costs. Given the lack of need for the capacity from the Wind Facilities, it might seem an imprudent decision to place the above cited long-term base rate cost responsibility on West Virginia ratepayers. The Companies argue, however, that the Wind Facilities are a physical hedge, providing a more certain and predictable cost for the energy produced by the facilities in lieu of buying that amount of energy. Thus, according to the Companies, West Virginia customers will actually benefit from the Wind Projects because the Companies believe that a comparable amount of energy that is needed to serve West Virginia customers will cost more if acquired from the PJM market. If the Companies analyses of the cost of power from the market is correct, then it would seem prudent to acquire the Wind Facilities. And therein lies our conundrum.

The prudence and reasonableness of incurring the cost of the Wind Facilities is dependent on the reasonableness and accuracy of the Companies' PJM market price forecasts. The Staff and CAD are convinced that there are sufficient, significant questions about the reasonableness of the market price forecasts that the Commission should render a decision similar to that recently made by the Virginia State Corporate Commission. WVEUG also questions the reasonableness of taking the eggs out of the market basket and relying on rate base generation for power that can come from the Wind Facilities.

There are multiple references in the record to the Net Present Value (NPV) of the revenue requirements of the Wind Facilities over twenty-five years (under) or over the NPV of purchases from the PJM market over the same twenty-five year period. To some extent, the record can become confusing because of the multiple NPV comparisons presented by the Companies in their original filing and direct testimony that were later adjusted by multiple NPV comparisons after the TCJA and renegotiated purchase terms resulted in changes in revenue requirements. Added confusion can arise because some witnesses of the Companies redacted NPV numbers while other witnesses of the Companies did not redact NPV numbers. In addition, the Companies sometimes refer to NPV after credits from the sale of RECs and at other times do not quantify the effects of RECs on NPV. Staff, CAD and WVEUG also filed updated data in response to the changing numbers filed by the Companies, but did not provide clear side-by-side type discussions and comparisons of their NPV projections to the Companies multiple projections and multiple scenarios.

Our reference to a confused record does not mean that it is unintelligible; instead, we mean that frequent shifting between original documents, adjusted documents, public documents and confidential documents is necessary to properly compare the positions of the parties. We will not attempt to summarize all of the NPV projections, iterations, simulations, and sensitivity analyses, both public and confidential, that the parties have sprinkled throughout the record. We do summarize below some of the NPV numbers, and comments provided by witnesses.

	Hardin	Beech Ridge II
	Net Present Value of 25 Year Revenue Requirements (Negative = Benefit) i.e. Project Revenue Requirements Are Below Market Positive = Detriment i.e. Project Revenue Requirements Are Above Market	
	Million $	Million $
Companies		
Carbon Cost Scenario Projections Before REC Credits	$ (42.9)	$ (14.8)
Carbon Cost Scenario Projections After REC Credits @ $7 per REC (MWh)	$ (59.4)	$ (20.0)
No Carbon Cost Scenario Projections Before REC Credits	$ (6.7)	$ (3.0)
Carbon Cost Scenario Projections After REC Credits @ $7 per REC (MWh)	Greater benefit per Companies testimony, but values not provided in public exhibits.	
WVEUG - Baron		
No Carbon Cost Scenario Projections Before REC Credits	$0 – If market prices are 2.9% lower than the Companies projections	$0 – If market prices are 3.9% lower than the Companies projections
Staff - Short		
No Carbon Cost Scenario Projections – Market Price Projections Adjusted Downward by Staff	$ 43.8	$ 13.0

This data, and wide differences of opinion by expert witnesses, boil down to the troublesome essence of the issues in this case. That is, whether it is odds-on likely, even money, or odds-on unlikely that the West Virginia revenue requirements of the power that will be generated from the Wind Projects will be cheaper on a NPV basis over the twenty-five year life of the facilities than purchases of equal quantities of power from the PJM market. The Companies claim that in one of their scenarios, which they consider the most likely scenario, their Monte Carlo simulations result in a 100% certainty that there is a significant beneficial NPV for West Virginia ratepayers. Mr. Baron, testifying for WVEUG, explained why the Monte Carlo simulations might not be selecting reasonable random values within the parameters of the probability distributions defined by the Companies. WVEUG Exh. SJB-D at 8 – 10. He was also kind enough to define the Monte Carlo simulation methods for the record.[5]

[5] A "Monte Carlo" analysis is probabilistic economic analysis which is designed to produce a probability distribution of "outcomes" based on assumed probability distributions of input factors. It provides a measure of the uncertainty of the economic costs and benefits of an investment decision (for example, purchase of a wind project) based on the uncertainty of the input factors into the analysis (for example, PJM market prices, wind turbine MWh output). Through a Monte Carlo analysis, it is possible to measure the likelihood of beneficial outcomes (i.e., an economically beneficial investment for customers), given the uncertainty of the key driving factors impacting the economic results. The analysis is performed by randomly selecting input assumptions, based on a probability distribution of each key input, and then calculating the economic outcome for the project. If this process is performed 100s or 1,000s of times, the result is a probability distribution of the economic costs and benefits of the project being analyzed. WVEUG Exh. SJB-D at 8.

The reasonableness of the Companies' market price forecasts and NPV benefits to West Virginia customers of owning additional energy producing facilities rather than relying on the market depends a lot on the forecasted costs of natural gas built into the Companies models. Tr. II at 55-56 (Scalzo). The Companies' projected natural gas prices appear to be high compared to the recent natural gas markets and are not supported by current or recent natural gas prices. For example, the Companies' projected Henry Hub natural gas price of $4.89/MMBtu for 2018 was an increase of more than fifty percent from actual gas prices for December 2017. Staff Exh. RRS-D at 16.

We are aware of the natural gas price spikes in 2005 and 2008. Those spikes may occur again, but over the last twenty years the spikes have been of relatively short duration, measured in months, and prices quickly settled back into the level or downward trends we have seen for the better part of twenty years. For example, in the last ten years, according to EIA data, Henry Hub gas prices dropped by 57%. That percentage is influenced by a very steep decline in the first two years of that period, and that steep decline has moderated. Even so, in the last eight years the Henry Hub gas prices dropped by 24%. Even if we assume a leveling off or reversal of the downward trend in natural gas prices, however, the Companies natural gas price forecasts are very aggressive on the up side.

In their Fundamentals Forecast, the Companies assume Henry Hub gas prices increasing by almost 200% in the first ten years of the forecast, going from $2.15 in 2016 to $6.40 in 2026. Extended to 2046, the Companies Henry Hub projected gas price is $11.34, an increase of 427% from the 2016 price. The Companies' Fundamentals Forecast for Appalachian gas prices show even sharper increases, with the Dominion South Point Pool projected to increase 312% from 2016 to 2026 and increasing 647% to 2046, and the TCO Appalachian Pool projected to increase 300% from 2016 to 2026 and 549% from 2016 to 2046.

The United States Energy Information Administration's 2018 long-term forecast shows record high natural gas production going forward through 2050 and adjusts forecasted natural gas prices downward fourteen percent from the 2017 long-term outlook. Tr. II at 96. The Fundamentals Forecast upon which the Companies rely was issued in 2016 and has not been updated to reflect more current prices and conditions. Staff Initial Brief at 9. We are concerned that the benefit of owning the Wind Facilities is supported by PJM market price projections that are dependent on the Companies 2016 Fundamentals Forecast showing near term Henry Hub price increases of 200% and 300% increases in Appalachian gas prices. We are equally concerned by the extended projections of 427% to 650% longer term increases in natural gas prices over the period of time generally covering the life of the Wind Facilities.

We are also concerned that just as the Companies Fundamentals Forecast is overly aggressive on natural gas prices, it is also overly aggressive on PJM market prices. The Fundamentals Forecast assumes a 31% increase in PJM on peak energy prices in one year, from 2017 to 2018. The same forecast assumes that from 2017 through 2029 (approximately the end of the first ten years of the Wind Facilities) the PJM on-peak energy price will increase 146% and by the end of the following fifteen years, the PJM on-peak energy price will be 281% higher than the 2017 price. We do not dismiss these levels of PJM energy price increases as impossible, but we do consider it to be more likely than not that the energy prices will not escalate as rapidly as reflected in the Companies projections.

There was also disagreement on the Companies' reliance on future carbon-related costs impacting the PJM market price upward. Staff, CAD and WVEUG all discounted the Companies carbon-cost scenario. We share that concern. There are not now, nor have there been, carbon regulations imposing such burdens on generators. Although it may be prudent for the Companies to consider the effect of possible carbon regulation on future costs, to rely completely on possible regulations that will not occur in the near future and may not occur in the distant future is too speculative to impose on current ratepayers.

Green Power as an Economic Development Tool

The Companies suggest in their Petition that certain large commercial or industrial customers desire electric power from renewable generation. Petition at 9. The Companies, however, offered no examples for this assertion in the form of descriptions of inquiries from potential customers. Mr. Scalzo admitted on cross-examination that the Companies did not have a potential commercial or large industrial customer requesting green power at this time. Tr. I at 272. The Companies, moreover, did not explain why, if they did receive such requests in the future, they could not satisfy the requests with the purchase of green power energy for the customer. Additionally, Company witness Mr. Karrasch testified that the purchase of these two Wind Facilities will not swing rates significantly to attract industrial customers. Tr. I at 78. We are not indifferent to the increasing public concern about the relative increase in electric rates. As a consequence, we are not inclined to lock-in twenty-five years of base rate costs for power supply that is just as likely to cost more than the market alternative as it is likely to cost less than the market alternative based on speculation that some future customer might want green power that is owned, rather than purchased, by the Companies.

Conditions or alternative rate setting procedure

The Commission has occasionally considered, suggested, or required certain conditions be met before some transaction we are asked to review and approve can be considered in the public interest. We asked Mr. Scalzo if there might be an innovative cost recovery proposal that would protect current and future customers from excessive costs if the Companies' projections of PJM energy prices turned out to be overstated.

> Chairman Albert: You also said that . . . you all would accept your proposal or some other innovative proposal. I think that's what your testimony was.
>
> And the Pleasants' case, we said that the Companies will compensate customers through prospective rate credits, as determined by the Commission, for any year that market sales produce revenues that are below the full requirements imposed on the customers. Is that something you would consider doing here?
>
> A. I think we'd have to take it back to management and evaluate it.

Tr. II at 47. Notwithstanding the question and answer, the Companies did not follow up with or suggest a rate mechanism proposal that would place any of the risk that their twenty-five year market price projections were inaccurate on the Companies. We are not inclined to engage in a fishing expedition to get a proposal from the Companies on any condition, deferral or alternative rate mechanism that would result in the Companies absorbing or even sharing the burden if their proposed physical hedge to the market turned out to be a losing hedge.

Accordingly, we base our decision on the Companies' proposed rate setting request, the potential benefits and detriments that acquisition of the Wind Facilities bring to the table and the fact that the required VSCC approval has been denied. Considering the lack of need for capacity, the availability of ample energy supplies from the PJM Market, the uneven potential benefits of the Wind Facilities as compared to the market option due to the fly-up revenue requirements beginning in eleven years and continuing for fifteen years thereafter, the aggressive projections of gas price and PJM market price escalation over the next twenty-five years, the uncertainty of the timing and impact of carbon regulations and their associated impact on market prices and fossil fuel generation, the uncertainty of the per unit value of RECs that would offset the costs of the Wind Facilities, and the complete lack of any record on how we could go forward with the Wind Facilities acquisition in view of the denial by the VSCC, the proposed acquisitions, under the conditions and circumstances set forth in this record, are not in the public interest in West Virginia.

<u>Protective Treatment</u>

On March 8, 2018, the Companies filed their Second Addendum to First Motion for Protective Treatment requesting that the Commission grant protective treatment to the confidential information in the Companies' February 28, 2018 supplemental rebuttal filing and March 8, 2018 corrective filing. On April 13, 2018, the Companies filed their Third Addendum to First Motion for Protective Treatment requesting that the Commission grant protective treatment to the confidential information in the Companies' April 6, 2018 Initial Brief. The Companies are seeking confidential treatment of the information in both addendums for the same reasons they sought confidential treatment in the First Motion for Protective Treatment and First Addendum to that motion. No party has objected to either request for protective treatment. The Commission deferred ruling on both the original motion and the first addendum until the filing and review of a request pursuant to the West Virginia Freedom of Information Act, W.Va. Code §29B-1-1 et seq. Likewise, the Commission will defer ruling on the third and fourth addendums to the Companies' Motion for Protective Treatment.

FINDINGS OF FACT

1. The Companies have sufficient capacity. Tr. II at 52-53 (Scalzo).

2. The low net cost to ratepayers in the first ten years due to the PTC creates a concern for fairness to future ratepayers who will be required to bear the higher costs in years eleven through twenty-five.

3. The Companies do not generate sufficient energy to serve their customers in the winter months.

4. PJM plans its supply resources to meet its summer peak demand and energy requirements and, therefore, has more than enough generating capability in the winter to make up for any shortfall between APCo's energy generation and its customer energy needs.

5. The VSCC held that APCo failed to establish that the wind facilities are needed to address an energy deficiency or that they would be likely to provide energy at a lower overall cost to customers. Appalachian Power Co., Commonwealth of Virginia State Corp. Comm'n., Case No. PUR-2017-00031, Final Order, April 2, 2018, at 4-5 (Reconsideration Denied, April 20, 2018).

6. The Companies did not present any evidence of commercial or industrial businesses that requested green energy as a condition of becoming customers.

7. The Companies seek protective treatment for certain information filed under seal on February 28, 2018, March 8, 2018, and April 6, 2018.

8. No party has objected to the request for protective treatment.

CONCLUSIONS OF LAW

1. Because of the availability of an ample wholesale purchase option from the PJM energy market, the Companies do not have a need to own or bi-laterally contract for additional energy to meet their internal load requirements.

2. The Commission is required by statute to appraise and balance the interest of current and future utility service customers. W.Va. Code §24-1-1(b).

3. The base rate revenue requirement over the entire twenty-five year life of the wind facilities, without the costs being allocated between West Virginia and Virginia, would total $839.6 million.

4. The Companies' natural gas prices are high compared to the recent natural gas markets and are not supported by current or recent natural gas prices.

5. The Companies' fundamentals forecast is overly aggressive on PJM market prices. It is more likely than not that the energy prices will not escalate as rapidly as reflected in the Companies projections.

6. It is not reasonable to rely on speculative carbon regulations that have not been promulgated.

7. The Commission will not rely on the possibility of unnamed commercial or industrial customers who might require green power to become customers of the Companies if that power was more expensive than the market alternative.

8. Because no party has objected to the request for protective treatment and no request has been filed pursuant to W.Va. Code §29B-1-1 et seq., it is reasonable for the Commission to defer ruling on the Second and Third Addendums to the First Motion for Protective Treatment.

ORDER

IT IS THEREFORE ORDERED that the Petition for Consent and Approval filed by Appalachian Power Company and Wheeling Power Company on July 5, 2017, is denied and the case is removed from the Commission's docket of open cases.

IT IS FURTHER ORDERED that a ruling on the requests for permanent protective treatment filed on March 8 and April 13, 2018, is deferred until the filing and review of a request pursuant to the West Virginia Freedom of Information Act, W.Va. Code §29B-1-1 et seq. The Executive Secretary shall maintain the unredacted version of the sealed filings in their current condition, separate and apart from the rest of the file pending further order.

IT IS FURTHER ORDERED that the Executive Secretary of the Commission serve a copy of this Order by electronic service on all parties of record who have filed an e-service agreement, and by United States First Class Mail on all parties of record who have not filed an e-service agreement, and on Commission Staff by hand delivery.

A True Copy, Teste,

Ingrid Ferrell

Ingrid Ferrell
Executive Secretary

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