PHILLIPS, GARDILL, KAISER & ALTMEYER, PLLC
LAWYERS
61 FOURTEENTH STREET
WHEELING, WEST VIRGINIA 26003
TELEPHONE (304) 232-6810
FAX (304) 232-4918

JAMES C. GARDILL
CHARLES J. KAISER, JR.
H. BRANN ALTMEYER *
EDWARD M. GEORGE, III
DENISE KNOUSE-SNYDER
RICHARD N. BEAVER
J. CHRISTOPHER GARDILL
ROBERT D. PLUMBY *
ANDREW R. THALMAN **
JACOB C. ALTMEYER *
JEFFERY D. KAISER *

JOHN D. PHILLIPS
(1906-2000)

WILLIAM A. KOLIBASH
OF COUNSEL

RAY A. BYRD
OF COUNSEL

* ALSO ADMITTED IN OH
** ALSO ADMITTED IN PA AND IN

July 29, 2022

Mr. Bernard Logan, Clerk
c/o Document Control Center
State Corporation Commission
Tyler Building – First Floor
1300 East Main Street
Richmond, Virginia 23219

Via Electronic Filing

RE: <u>Appalachian Power Company – Case No. PUR-2022-00001</u>
Petition for approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia
Direct Testimony on behalf of the West Virginia Coal Association, Inc.

Dear Mr. Logan:

Please find enclosed the direct testimony of Emily S. Medine on behalf of the West Virginia Coal Association, Inc., for filing in the above referenced matter. The same has been served on all parties of record as reflected in the Certificate of Service.

Thank you for your attention to this matter. Please feel free to contact me with any questions or concerns.

Sincerely,

Jacob C. Altmeyer, Esq.

JCA/
Enclosures

{P0340063.1}

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

PETITION OF
APPALACHIAN POWER COMPANY **Case No. PUR-2022-00001**
For approval of a rate adjustment clause, the E-RAC, for costs to comply with state and federal environmental regulations pursuant to § 56-585.1 A 5 e of the Code of Virginia

DIRECT TESTIMONY OF

EMILY S. MEDINE

ON BEHALF OF THE

WEST VIRGINIA COAL ASSOCIATION

July 29, 2022

Summary of the Direct Testimony of Emily S. Medine

The purpose of my testimony is to provide my expert opinion on whether the Virginia State Corporation Commission (the "Commission") should approve the petition of Appalachian Power Company (the "Company") for the proposed rate adjustment clause (the E-RAC) for costs to comply with the Virginia jurisdictional costs related to the compliance with the Effluent Limitation Guideline (ELG) regulations pursuant to § 56-585.1 A5 e of the Code of Virginia at the Amos and Mountaineer stations. In December 2020, the Company sought approval for the jurisdictional costs associated with compliance with both the Coal Combustion Residuals (CCR) and ELG regulations. The Commission approved proceeding with CCR compliance but not with ELG. The West Virginia Public Service Commission, which had approved the West Virginia jurisdictional costs, expanded its approval to fund the entire ELG compliance costs on Amos and Mountaineer with the condition that after 2028 all of the energy and capacity at Amos and Mountaineer would be for the benefit of West Virginia.

This Commission's Order was without prejudice leaving the door open to the Company to ask for a reconsideration of the ELG funding. This Petition represents the Company's effort to seek reconsideration from the Commission in light of the reality that Amos and Mountaineer could continue to operate after 2028 as a result of West Virginia's funding, for the sole benefit of West Virginia ratepayers, with no power being provided to Virginia ratepayers absent the additional cost of a power purchase agreement from said plants. If Virginia does not participate, the jurisdictional customers would continue to be responsible for the remaining book value of these plants but would not have access to this capacity and/or power absent a separate purchase agreement. The analysis provided in the Petition demonstrates that there would be a significant cost savings to Virginia jurisdictional customers if the Commission approves this Petition, thereby allowing access to Amos and Mountaineer for energy and capacity after 2028.

My testimony supports the Company's proposal for many reasons. I found the Company's analysis compelling given that the relatively modest costs associated with ELG compliance are dwarfed by the costs associated with replacement of the Virginia jurisdictional share of capacity. The Net Present Value (NPV) analysis, however, was problematic because (1) it did not adjust the life of new gas investments to be consistent with the AEP corporate decarbonization plan and (2) the analysis was extended through 2051 despite the fact that the emerging generation options - such as green hydrogen, small modular nuclear reactors, carbon capture, and advanced battery concepts - were not included. Such resources are needed to achieve AEP's corporate decarbonization plan. I also believe the benefits are understated by failing to reflect the dramatic changes in global energy markets over the last 12 months, by failing to recognize and quantify the benefits of the ELG investment as a hedge against future market volatility, and by failing to reflect the benefits associated with a delay in selecting future capacity replacements until there is greater clarity as to what the resources should be.

I. INTRODUCTION AND QUALIFICATIONS

Q. WHAT IS YOUR NAME AND BUSINESS ADDRESS?

A. My name is Emily S. Medine. I am employed by Energy Ventures Analysis, Inc. My business address is 8045 Leesburg Pike, Suite 200, Vienna, VA 22182.

Q. FOR WHOM ARE YOU TESTIFYING IN THIS HEARING?

A. I am testifying on behalf of the West Virginia Coal Association, Inc..

Q. WHAT IS YOUR EDUCTION AND EXPERIENCE?

A. My education and experience is set out in Attachment I.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONEY?

A. The purpose of my testimony is to provide my expert opinion on whether the Virginia State Corporation Commission (the "Commission") should approve the petition of Appalachian Power Company ("APCo" or the "Company") for the proposed rate adjustment clause (the E-RAC) for costs to comply with ELG regulations pursuant to § 56-585.1 A5 e of the Code of Virginia.

Q. WHAT COSTS ARE THE COMPANY SEEKING TO RECOVER?

A. The Company lists five categories of costs, two of which have already been approved. The remaining three categories are as follows:

- Costs related to compliance with Effluent Limitations Guidelines (ELG) rule which the Commission denied without prejudice in the order to Case No. PUR 2020-00258,
- Capital costs related to dissolved oxygen levels at the Company's Claytor Hydro Project ("Claytor") and the dry sorbent injection at Amos.
- Actual and projected costs to associated with Virginia's membership in the Regional Greenhouse Gas Initiative (RGGI) with the dispatch of the Company's gas-fired Clinch River Plant.

Q. WHAT COSTS DO YOU ADDRESS IN YOUR TESTIMONY?

A. I address only the costs related to ELG compliance.

Q. DO YOU AGREE WITH THE COMPANY'S DISCUSSION OF THE HISTORY RELATED TO ITS EFFORTS TO OBTAIN APPROVAL FOR THE ELG COSTS?

A. Yes.

Q. DO YOU AGREE WITH THE REASONS PROVIDED FOR THE COMMISSION TO NOW SUPPORT THE ELG COSTS?

A. I support the reasons the Company provided to support the change in the Commission's position. I also believe there are additional reasons to support this investment beyond what the Company has offered.

Q. WERE YOU INVOLVED IN THE WEST VIRGINIA PROCEEDING CASE 20-1040-E-CN REGARDING THE COMPANY'S REQUEST FOR APPROVAL FOR ELG COMPLIANCE COSTS?

A. Yes. In Case 20-1040-E-CN, APCo and Wheeling Power Company ("WPCo") sought approval for the West Virginia jurisdictional shares of compliance costs for the Coal Combustion Rule (CCR) and Effluent Limitation Guideline (ELG) regulations for the Amos, Mitchell and Mountaineer stations from the West Virginia Public Service Commission ("WV PSC"). I provided testimony on behalf of the West Virginia Consumer Advocate Division ("WVCAD") in that proceeding as well as in Case No. 21-0810-E-PC, a subsequent proceeding seeking approval of an Amended Mitchell Operating Agreement and a new Mitchell Ownership Agreement.

Q. WHAT INFORMATION DID YOU REVIEW IN THIS ENGAGEMENT?

A. I reviewed the following documents:

- Filings and the responses to the data requests submitted in this Case.
- The filings in the related cases in West Virginia and Kentucky
- Relevant industry information.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. The next section reviews the Company's Petition and arguments in favor. It is followed by the additional reasons for support. The final section summarizes my recommendations.

II. THE PETITION

Q. WHAT ANALYSIS OF GENERATION OPTIONS DID APCO PROVIDE IN THE PETITION?

A. As APCo is required to comply with the requirements of the Virginia Clean Energy Act (VCEA), it developed six scenarios, all of which would comply with the VCEA.[1] The first four portfolios assume only the minimum level of renewable resources needed to meet the VCEA energy targets. Those four portfolios vary with respect to the retirement of Amos and Mountaineer in 2028 and 2040 and whether new gas resource options are considered.

TABLE 1: PORTFOLIO DESCRIPTIONS

Portfolios					
1	2	3	4	5	6
RGGI Only CO2 2040 AM & MNTR Ret. Gas Options Available	RGGI to $15 CO2 2040 AM & MNTR Ret. No Gas Option Available	RGGI Only CO2 2028 AM & MNTR Ret. Gas Options Available	RGGI to $15 CO2 2028 AM & MNTR Ret. No Gas Option Available	RGGI to $15 CO2 2040 AM & MNTR Ret. No Gas Option Available Higher Wind Limits	RGGI to $15 CO2 2040 AM & MNTR Ret. No Gas Option Available Current Wind Project Cap Factors

Portfolio 5 assumed an additional 1000 MW of wind is available and can be added based upon favorable economics in time to capture production tax credits before they expire in 2026. The sixth portfolio is a sensitivity case prepared at the request of the Commission. All scenarios assumed Virginia would continue its membership in RGGI.[2]

Q. WHAT RESOURCES DID APCO ASSUME WERE AVAILABLE?

A. The new resources considered by APCo are listed below.[3]

---

[1] Martin Testimony, Schedule 1, Part 1, page 73.
[2] While Governor Youngkin had indicated his intentions to withdraw RGGI, it is not clear this will happen.
[3] Martin Testimony, Schedule 1, Part 1, page 97.

TABLE 12: NEW RESOURCE LIMITATIONS

New Resource Assumptions							
Resource Type	First Year Available	Life	Portfolio 1,2,6	Portfolio 3 &4	Portfolio 5	Individual Technology Total	Cumulative Technology Total
Solar PPA	1/1/2025	35 years	150 MW/yr	300 MW/yr	150 MW/yr	900 MW	3,150 MW
Solar Utility T1		35 years	300 MW/yr	600 MW/yr	300 MW/yr	2,100 MW	
Solar Utility T2		35 years	150 MW/yr	300 MW/yr	150 MW/yr		
Solar Hybrid		35 years	150 MW Block 450 MW/yr			1,050 MW	
Wind PPA Limits	1/1/2026	30 years	100 MW/yr	300 MW/yr	100 MW/yr	350 MW Total	950 MW
Wind Owned Limits	1/1/2026	30 years	200 MW/yr	600 MW/yr	-	600 MW Total	
Wind Owned Limits	1/1/2026	30 years	- - - - -	- - - - -	2026 1,200 MW 2028 2,600 MW 2030 3,600 MW 2032 4,600 MW 2035 5,000 MW	5,000 MW Total	5,350 MW
Renewable Energy Certificates	1/1/2025	5 years	20 Blocks/yr			~7,000 GWh	~7,000 GWh
Stand Alone Storage	1/1/2025	10 years	2,500 MW/yr			12,500 MW	12,500 MW
NG 240 MW Combustion Turbine	1/1/2026	30 years	P1 unlimited P2 N/A	P3 unlimited P4 N/A	N/A	Unlimited	Unlimited
NG 1,100 MW Combined Cycle	1/1/2026	30 years	P1 unlimited P2 N/A	P3 unlimited P4 N/A	N/A	Unlimited	Unlimited

Q. DOES APCO CONSIDER NEW TECHNOLOGIES IN ITS ANALYSIS?

A. APCo acknowledged there are new technologies that could be resource alternatives in the future but are not included in the modeling. The specific options mentioned in the Petition are carbon capture and storage, hydrogen-capable combustion turbines, long duration storage, and small modular nuclear reactors (SMRs).[4] It is also worth noting that if the Inflation Reduction Act of 2022 is signed into law, the 45Q tax credit for carbon capture sequestration would be increased to $85/ton of carbon which makes a carbon capture retrofit on the Mountaineer station an interesting option. Mountaineer has previously been deemed an attractive site.[5]

Q. DO YOU AGREE THAT THIS APPROACH IS APPROPRIATE?

A. Yes and no. I agree that these technologies are potentially viable and I agree they may not yet be ready for selection in resource decisions. I would, however, have added to the discussion the point that by continuing to operate Amos and Mountaineer beyond 2028

[4] Martin Testimony Schedule 1, Part 1, page 89.

[5] https://netl.doe.gov/sites/default/files/environmental-policy/cis-mountaineer/Summary.pdf

there will be greater clarity as to which technologies should be pursued. In other words, committing to a CCGT at this time is premature if a full conversion to hydrogen is not possible without significant expense and if there is no better evidence than exists today that green hydrogen is expected to be available and competitive.

Q. DO YOU HAVE ANY ISSUES WITH THE INCLUSION OF COMBINED-CYCLES NATURAL GAS TURBINES (CCGT) IN CASES 1 AND 3?

A. CCGT's are a mature technology. The problem with CCGT's is that, absent a carbon capture retrofit or conversion to green hydrogen, they are not consistent with AEP's decarbonization strategy. Neither carbon capture retrofits nor green hydrogen conversions are reflected in the CCGT costs.

Q. WHAT IS AEP'S DECARBONIZATION STRATEGY?

A. According to AEP, its goal is to reduce carbon emissions from owned generation by 80 percent by 2030 (compared to 2000 levels) and "to achieve net-zero emissions by 2050." Note the former refers to Scope 1 emissions, the later to Scope 1 and 2 emissions.[6] AEP further indicates that it is "committed to periodically reviewing these goals as (it) works toward a clean energy future."[7]

Q. WHAT IS THE ISSUE WITH CCGT'S IN THIS STRATEGY?

A. APCo models the new CCGT's with a 30-year life as shown in the New Resource Limitations schedule above. This means the costs are depreciated over a 30-year period. Given the AEP plan to achieve net-zero emissions by 2050, if the CCGT's are being added to replace Amos and/or Mountaineer in 2028, there are only 21 years until the CCGT would have to be shuttered, converted to green hydrogen, or retrofitted with carbon capture. If they are being added in 2040, they would have only a 10-year window.[8] Given the costs and technology associated carbon capture and green hydrogen are uncertain, the prudent

[6] Scope 1 emissions directly from owned-or-controlled sources in on-site power generation, fleet vehicles, etc. Scope 2 are indirect emissions from electricity purchased and used by the organization.
[7] https://aepsustainability.com/
[8] Another option could be the purchase of offsets. Offsets are not discussed in APCo's testimony.

analytical assumption is to require the investment be justified over the shorter economic life.

Q. WHAT WERE THE RESULTS OF APCO'S ANALYSIS?

A. APCo uses the net present value (NPV) of revenue requirements to compare the portfolios.[9] The lowest cost case for the six scenarios was Portfolio 1 which assumed ELG compliance at Amos and Mountaineer with a gas option. The next lowest cost portfolio was Portfolio 3 which is the retirement of Amos and Mountaineer in 2028 with a gas option.

TABLE 18: NPV OF PORTFOLIO REVENUE REQUIREMENTS

Column	1	2	3	4	5	6
	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5	Portfolio 6
Customer Revenue Requirements	2040 AM+MNTR Ret. RGGI CO2 Gas Option	2040 AM+MNTR Ret. RGGI-$15 CO2 No Gas Option	2028 AM+MNTR Ret. RGGI CO2 Gas Option	2028 AM+MNTR Ret. RGGI-$15 CO2 No Gas Option	2040 AM+MNTR Ret. RGGI-$15 CO2 No Gas Option High Wind Units	2040 AM+MNTR Ret. RGGI-$15 CO2 No Gas Option Historical Wind CF
Net Present Value $M						
Utility NPV 2021-2027	$4,837	$4,839	$4,823	$5,018	$4,894	$4,850
Utility NPV 2028-2039	$7,047	$8,132	$8,615	$10,643	$8,041	$8,218
Utility NPV 2040-2051	$5,242	$6,078	$4,869	$5,878	$5,980	$6,435
NPV of End Effects beyond 2051	$4,494	$5,662	$4,556	$5,706	$5,276	$5,762
TOTAL Utility Cost, Net Present Value	$21,620	$24,710	$22,863	$27,245	$24,191	$25,266

Q. BASED UPON YOUR DISCUSSION ABOVE, DO YOU BELIEVE THAT PORTFOLIOS 1 AND 3 REFLECT COSTS CONSISTENT WITH AEP'S DECARBONIZATION STRATEGY?

A. As the gas option does not reflect a shorter amortization period consistent with net zero in 2050, the "Gas Option" portfolios, i.e. Portfolio 1 and Portfolio 3, do not reflect costs consistent with AEP's decarbonization strategy.

Q. DO YOU BELIEVE THE NPV ANALYSIS AS PRESENTED IS APPROPRIATE?

A. No, for many reasons. The costs and selections post 2040 are speculative at best and do not include emerging technologies that many (including AEP) think will be available, economic, and appropriate post 2040. Further, compliance with AEP's decarbonization strategy does not appear to be reflected.

Q. HOW WOULD YOU CONSIDER THE RESULTS DEVELOPED BY AEP?

---

[9] Martin Testimony, Schedule 1, Part 2, page 3.

A. For the purposes of this proceeding given the uncertainty as to future resource options and the expected 2040 retirements of Amos and Mountaineer, it is best to consider the NPV results only through 2039 as shown below. Portfolio 1 is nine to 32 percent less expensive over this period.

NPV Analysis Results (Million Dollars)

Period	Portfolio					
	1	2	3	4	5	6
2021-2027	4,837	4,839	4,823	5,018	4,894	4,850
2028-2039	7,047	8,132	8,615	10,643	8,041	8,218
Total	11,884	12,971	13,438	15,661	12,935	13,068
Portfolio Costs vs Portfolio 1 Costs		9%	13%	32%	9%	10%

Q. **ARE THERE COSTS MISSING FROM THIS ANALYSIS?**

A. Yes. The Company did not include potential transmission costs in the Petition. According to the Martin Direct Testimony, the analysis "did not include an assumption of interconnection costs in the cost of the replacement assets, beyond routine interconnection costs assumed to be generic resources."[10] Witness Martin estimated that "the costs of getting enough transmission for the thousands of nameplate MW needed to replace Virginia's half of the plants could be $50-$100 million depending on the location of replacement capacity."

III. APCO ARGUMENTS IN FAVOR OF APPROVAL OF ELG COST RECOVERY

Q. **PLEASE SUMMARIZE WHAT YOU BELIEVE ARE THE COMPANY'S ARGUMENTS IN FAVOR OF APPROVAL OF THE ELG COSTS?**

A. There are three primary arguments:

- Because of the decision by the WVPSC, the Amos and Mountaineer plants will comply with the ELG rule by the end of 2025 and will be operated for an indeterminate period thereafter. Absent the appropriate jurisdictional contribution of costs by Virginia ratepayers, Virginia ratepayers will not be entitled to the capacity and energy from

[10] Martin Direct Testimony, Part 1, page 66.

these plants after 2028 pursuant to the WVPSC Order, which APCo affirms in this Petition.[11]

- The estimated cost of replacement capacity by the end of 2028 at $2.8 to $3.4 billion dwarfs the incremental costs to fund the ELG compliance, which the Company estimates to be $98 million. Virginia ratepayers would also continue to be responsible for their share of the remaining undepreciated costs of these stations. Given the relatively small incremental cost, this investment is effectively a hedge against higher costs.
- Absent the ELG investment, there could be complications related to how West Virginia and Virginia structure the removal of Virginia ratepayers' rights to the capacity and energy of Amos and Mountaineer.

Q. HOW DID IT COME TO BE THAT WEST VIRGINIA AGREED TO FUND THE FULL ELG COMPLIANCE COSTS FOR AMOS AND MOUNTAINEER?

A. In November 2020, APCo and WPCo filed Case 20-1040-E-CN for approval of the West Virginia jurisdictional costs related to CCR and ELG compliance at the Amos, Mitchell, and Mountaineer stations. In December 2020, APCo filed Case No. PUR 2020-00258 in Virginia for approval of the Virginia jurisdictional costs related to CCR and ELP compliance at Amos and Mountaineer. In February 2021, Kentucky Power ("KPCo") filed Case 21-00004 in Kentucky for approval of the CCR and ELG compliance costs of KPCo's undivided 50 percent interest in the Mitchell station.

The WVPSC issued three substantive Orders in Case No. 20-1040-E-CN. The first order ("August 4, 2021 Order") approved the CCR and ELG costs associated with the West Virginia jurisdictional share of the expenditures necessary to comply with the ELG rule. The Commissions in Kentucky and Virginia approved the CCR costs but not the ELG expenditures.

The second Order ("September 9, 2021 Order") approved the request for a rehearing on certain matters, most notably confirmation that the WVPSC would support recovery of all ELG expenses at the plants, i.e., both jurisdictional and non-jurisdictional.

---

[11] Petition, Part 1, page 8.

The third Order ("October 12, 2021 Order") confirmed West Virginia would pay for the entire ELG expenses at the plants and that after 2028 the capacity and energy produced by these plants would be for the benefit of West Virginia ratepayers only. The WVPSC concluded that it believed it had two choices which it laid out as follows:

> *Thus, our choices are: (i) to direct APCo to proceed with the investments necessary to allow all three Plants to remain open beyond 2028 and to agree to share CCR costs with Kentucky, Virginia, and FERC jurisdictional customers and to share ELG compliance costs with FERC jurisdictional customers only with those total costs before allocation being approximately $448.3 million, or (ii) to follow the Virginia and Kentucky approach which will require premature retirement of the Plants and burden West Virginia customers with replacement capacity costs of $1.9 to $2.3 billion. Said another way, even if the total cost of compliance was allocated to West Virginia customers (which is not the case) the additional rate base cost would be only $448.3 million compared to West Virginia customers paying between $1.9 and $2.3 billion for replacement capacity costs.*[12]

In other words, the WVPSC concluded that if the total cost of ELG compliance was added to the APCo's West Virginia's rate base, it would still be materially less than the cost of replacement capacity for APCO's West Virginia jurisdictional customers.

Q. DO YOU AGREE WITH THE COMPANY'S POSITION THAT VIRGINIA JURISDICATIONAL CUSTOMERS WOULD NOT BE ENTITLED TO ENERGY OR CAPACITY FROM AMOS AND MOUNTAINEER AFTER 2028?

A. Yes. The October 12, 2021 Order was clear in this regard. The WVPSC notes that the ability to continue to operate Amos and Mountaineer after 2028 could provide value to West Virginia customers through the sales of energy and capacity, as described below:

> *By confirming our decision to proceed with the CCR and ELG compliance, after 2028 West Virginia customers will receive the full capacity and energy capabilities of three West Virginia coal plants capable of operating to at least 2040. The Plants could then provide West Virginia's PJM demand capacity requirements and produce excess capacity that could be sold through some combination of bi-lateral PPAs, RTO capacity bids, and affiliated agreements. The Plants could also provide base load energy for West Virginia needs and excess energy that could likewise be sold. To the extent excess capacity and energy are sold, the revenue received would be credited for ratemaking purposes to the benefit of West Virginia customers.*[13]

[12] http://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=573045&NotType=WebDocket, Page 6

[13] http://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=573045&NotType=WebDocket, Page 7.

Q. IS WV PSC's FINDING CONSISTENT WITH APCO'S POSITION IN THIS CURRENT PROCEEDING?

A. Yes. APCo has demonstrated that the cost of capacity replacement for Virginia jurisdictional customers would cost between $2.8 and $3.4 billion which would cause customer rates to increase by 17 to 29 percent in 2029.[14] Further APCo acknowledges it would not have access to the energy and capacity of Amos and Mountaineer after 2028 unless there was a power purchase agreement.

Q. DO YOU AGREE THAT ABSENT THE ELG INVESTMENT, THERE COULD BE COMPLICATIONS BETWEEN WEST VIRGINIA AND VIRGINIA RELATED TO THE CONTINUED OPERATIONS OF AMOS AND MOUNTAINEER?

A. I do not believe that there would necessarily be complications. I believe the Company has concerns, given what is currently occurring between Kentucky and West Virginia regarding the Mitchell plant. The Mitchell situation is very different. AEP is trying to close the sale of Kentucky Power to Algonquin Energy subsidiary Liberty Utilities for $2.85 billion.[15] If the sale is closed, the owner of the 50 percent undivided share of Mitchell would no longer be an AEP affiliate. Further Liberty Utilities has been transparent as to its intention to "green the fleet"[16] as soon as possible which creates a disparity between WPCo and KPCo as to how the Mitchell station is operated. At this point, it appears KPCo is unwilling to address the concerns of the WVPSC regarding how the plant is operated until 2028 and the rights West Virginia has to the energy and capacity associated with KPCo's share of Mitchell after 2028.

Given the Company's acknowledgement in the Petition that it understands post 2028, absent approved ELG funding by this Commission, Virginia jurisdictional customers have no rights to the capacity and energy and the net book value at the time remains with Virginia jurisdictional customers, a similar dispute is unlikely.[17]

---

[14] Petition, Martin Direct Testimony, page 4.

[15] https://aep.com/news/releases/read/7276/AEP-to-Sell-Kentucky-Operations-to-Liberty-Subsidiary-of-Algonquin-Power-and-Utilities

[16] https://kentucky.gov/Pages/Activity-stream.aspx?n=AttorneyGeneral&prId=1188

[17] Petition, Martin Direct Testimony, page 8, lines 7-20 (Part 1, page 47)

IV. ADDITIONAL REASONS TO SUPPORT ELG COMPLIANCE FUNDING

Q. OVER THE LAST 12 MONTHS HAVE THERE BEEN DRAMATIC CHANGES IN THE GLOBAL ENERGY MARKET THAT SHOULD BE CONSIDERED BY THE COMMISSION?

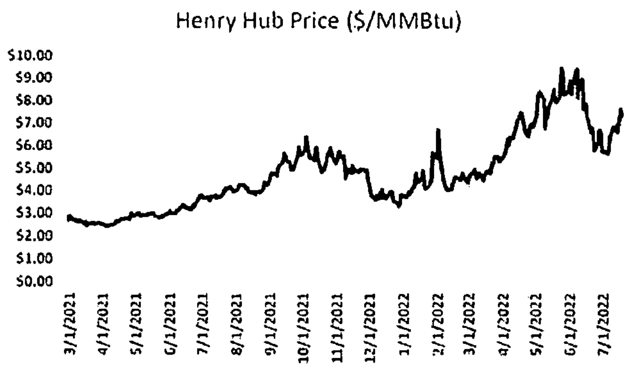
A. Yes. A combination of faster than expected demand recovery from COVID, persistent supply chain disruptions, and the war in Ukraine all have produced unexpected market changes.

Q. WHAT ARE YOUR SPECIFIC CONCERNS?

A. I am specifically concerned about natural gas pricing and availability, and supply chain delays that would affect the Company's analysis weighing the costs of replacement capacity against the benefits of funding ELG compliance costs.

Q. HOW HAVE NATURAL GAS PRICES CHANGED SINCE THE FILING?

A. Natural gas prices have increased substantially since March 2021, reaching levels not previously predicted. Further, volatility has increased.



Source: https://www.eia.gov/dnav/ng/ng_pri_fut_s1_d.htm

Q. WHAT ARE THE REASONS FOR THE INCREASED GAS PRICE AND VOLATILITY?

A. There are numerous factors in play. Generally, the most significant was that demand recovery outpaced the recovery in supply. Relatively low energy prices for gas, power, coal, and even oil in 2019 and 2020 resulted in a lack of CAPEX spending as producers focused on cash flow rather than investment in new capabilities. When the post COVID demand recovery started, the industry had to play catchup. Additionally, coal and gas prices have become more connected to export market pricing and capabilities. Greenfield pipelines needed to deliver natural gas to demand centers from supply areas like Appalachia have been nearly impossible to finalize. New natural gas supply is essential given the ever-changing supply stack in power with coal plant retirements, new natural gas (both combined-cycles and combustion turbines) and installations of intermittent renewable resources.

Q. DID COAL PRICES ALSO INCREASE DURING THIS PERIOD?

A. Yes. Coal had similar problems related to recovery as utility inventories had increased during COVID and in the rush to reduce inventory levels. The coal industry did not anticipate the underlying increase in coal demand and, therefore, was slow to reactivate production levels. This was complicated by strong global demand which affected domestic coal pricing because of diversion of domestic coal into the export market and supply chain shortages. However, coal production has increased recently and supply levels are consistently recovering.

Q. HOW DO NATURAL GAS PRICES AND COAL PRICES INTERACT?

A. Since the shale revolution over a decade ago, a coal-gas switching relationship in the power sector developed. Coal plant dispatch would increase with high gas prices which effectively capped the increase in gas prices. In the last year this relationship changed. In many regions there was inadequate coal supply at coal fired power plants which, when coupled with the reduced overall coal-fired capacity due to extensive coal-fired plant retirements, eliminated the aforementioned coal influenced cap on natural gas prices. As a result, natural gas prices increased rapidly in those regions.

Q. WITH ADDITIONAL COAL PLANT RETIREMENTS, DO YOU EXPECT THE HISTORICAL RELATIONSHIP BETWEEN COAL AND GAS PRICING TO RESUME?

A. This depends upon the amount of the retirements. As coal plant retirements increase, the ability of coal-fired plants to operate as a competitive cap to natural gas prices is eliminated.

Q. TO WHAT DO YOU ATTRIBUTE THE RECENT DIP IN NATURAL GAS PRICES?

A. I believe there are two primary factors. First, and most significant, is the outage at the Freeport LNG facility, which has reduced demand by about two billion cubic feet (BCF) per day. While there is some uncertainty as to the timing of the restart of Freeport, there is no debate that it will return to service. Second is the typical seasonal fluctuations due to weather, which have been exacerbated as the consumption of natural gas in the utility sector has increased. Without significant natural gas storage options, prices are sensitive to daily demand swings. Natural gas is already back to trading above $6.50 per MMBtu which is more than twice the historical averages seen since the shale era began.

Q. HOW IS NATURAL GAS TYPICALLY PRICED TO REGULATED UTILITIES?

A. Typically, utilities purchase natural gas at the prevailing market price. While limited hedging does occur, it is generally seen to be a high-risk practice for regulated utilities.

Q. DO YOU BELIEVE THAT INCREASED RELIANCE ON NATURAL GAS FOR GENERATION WILL INCREASE RISKS TO RATEPAYERS?

A. Yes. As noted, utilities are exposed to price swings. Further, if there are significant coal plant retirements without replacement by other dispatchable generation, such as small modular nuclear reactors (SMRs) or significant battery penetration, natural gas prices for the utility sector will not be influenced by other sources of generation.

Q. DO YOU HAVE THE SAME CONCERNS ABOUT LONG-TERM COAL PRICING AS YOU DO WITH RESPECT TO NATURAL GAS PRICING?

A. No, for two reasons. First, the current problems largely reflect short-term supply issues which can and will be resolved in short order. Second, the ability for the U.S. to increase coal exports is limited due to terminal capacity constraints along the U.S. East Coast which, unlike LNG capacity, are unlikely to be resolved.

Q. **HAVE THE SUPPLY CHAIN DISRUPTIONS AFFECTED THE POWER INDUSTRY?**

A. Throughout the U.S., utilities are experiencing delays in bringing on new resources as a result of global supply chain problems. Several recent examples include:

- We Energies announced on June 23, 2022 its plans to extend the operating lives of the four older units at its Oak Creek site. "The decision to postpone the retirement dates for these units is based on two critical factors: tight energy supply conditions in the Midwest power market and supply chain issues that will likely delay the commercial operation of renewable energy projects that are currently moving through the regulatory approval process.[18]
- Omaha Public Power District announced on June 16, 2022 that it is proposing to delay conversion of its North Omaha Station coal units from 2023 to 2026 citing delays in new natural gas balancing stations, new solar projects, and other supply chain challenges.[19]
- CEO Nick Akins of American Electric Power addressed supply chain disruptions in its First Quarter 2021 Earnings Call[20]. He noted that "two new natural gas generation projects have experienced some siting and grading delays, as well as supply chain issues.... The new solar generation projects have also experienced challenges with siting of projects and supply chain challenges."

---

[18] https://news.we-energies.com/we-energies-announces-new-timeline-for-oak-creek-plant-retirements/
[19] https://www.oppd.com/news-resources/news-releases/2022/june/oppd-recommends-delaying-transition-of-north-omaha-station/
[20] Full Earnings Call transcript: https://seekingalpha.com/article/4504662-american-electric-power-company-inc-aep-ceo-nick-akins-on-q1-2022-results-earnings-call

- Duke Energy said it expected delays in renewable projects due to supply chain constraints. The timing of commercial renewable projects will shift with the five-year plan and several hundred megawatts are pushed from 2022 to 2023 or later.[21]
- Northern Indiana Public Service Company is delaying the retirement of its coal-fired Schahfer station as a result of delays in its solar projects.[22]

While these delays are represented as "short-term" events, the reality is that new projects that are not yet in transmission queues are also likely to be delayed.

Q. DOES THIS MEAN THAT THE NEED TO REPLACE 2100 MW'S OF CAPACITY IN 2028 WOULD EXPOSE RATEPAYERS TO MARKET PURCHASES AND ITS ASSOCIATED VOLATILITY?

A. Yes.

Q. HOW HAS THE WAR IN UKRAINE AFFECTED DOMESTIC ENERGY MARKETS?

A. The war in Ukraine has affected global energy markets which have in turn affected domestic energy markets. Europe is in the process of weaning itself from Russian imports of both natural gas and coal. With respect to natural gas, this is expected to accelerate the next wave of LNG development in the US. The White House and EU's agreement[23] to materially increase US LNG supply for Europe is likely to accelerate a number of projects, including Plaquemines, Corpus Christi Stage III, Driftwood LNG, and Freeport LNG which total over 6.5 BCFD. A summary of current LNG development efforts is provided below.

---

[21] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/supply-chain-issues-delaying-some-duke-energy-commercial-renewable-projects-68846077

[22] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/nisource-expects-solar-project-delays-extends-life-of-ind-coal-plant-70152518

[23] https://www.whitehouse.gov/briefing-room/statements-releases/2022/03/25/fact-sheet-united-states-and-european-commission-announce-task-force-to-reduce-europes-dependence-on-russian-fossil-fuels/

U.S. LNG project by permitting status

Under Construction
Golden Pass T1-3 Calcasieu Pass Phase 2
Driftwood Plaquemines Phase I

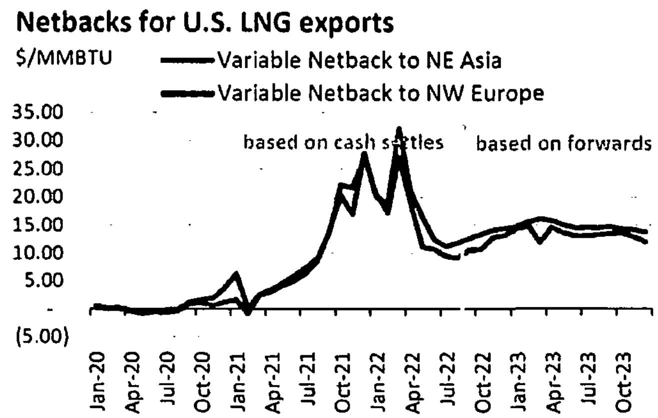
FERC Approved
Corpus Christi Midscale Magnolia LNG T1-4
Lake Charles T1-3 Freeport T4 Plaquemines Cameron T4-5
Jacksonville Eagle T1-3 Delfin FLNG Port Arthur T1-2 Gulf LNG
Annova LNG Rio Grande LNG Texas LNG Jordan Cove Alaska LNG

Under FERC Review
Galveston Bay LNG Point Comfprt LNG
West Delta LNG

Under Pre-Filing Process
Pointe LNG West Delta LNG
Port Arthur Expansion Delta Fourchon LNG Commonwealth LNG Monkey Island

Source: EVA Quarterly LNG Outlook, Q2 2022

The strong interest in LNG is due to high global pricing which produces high netbacks for U.S. LNG exports as shown below. The net effect is a strong economic preference for natural gas to move into the LNG market versus the domestic markets.



Source: EVA Quarterly LNG Outlook, Q2 2022

Q. ARE THERE ANY OTHER FACTORS THAT YOU BELIEVE THAT SHOULD BE CONSIDERED REGARDING THIS PETITION?

A. As alluded to above, the Commission should explicitly consider this approval as a hedge against market volatility, as insurance against supply chain issues, and, most importantly, an opportunity to gain clarity on which new resources should be pursued.

Q. WITH RESPECT TO THE VALUE OF TIME IN DETERMINING THE APPROPRIATE FUTURE RESOURCE OPTIONS, DO YOU BELIEVE THAT AEP BELIEVES EMERGING TECHNOLOGIES COULD BE PART OF ITS FUTURE?

A. Yes. In November 2021, Paul Chodak III delivered testimony before the Senate Energy and Natural Resources Committee.[24] Mr. Chodak, AEP's Executive Vice President of Generation, explained why the new generation of nuclear plants provide a potential resource that needs to be considered.

> *The reactors in the current fleet are very large, typically 600-1,400 MWe, and were mostly constructed on their operating sites, resulting in lengthy and expensive construction schedules. Advanced reactors are smaller, typically 60-300 MWe, simpler, and utilize modular construction techniques. They are referred to as small modular reactors (SMRs). The size and inherent safety features of these designs eliminate the need for many systems, greatly simplifying the design and construction. In addition, modular construction techniques enable much of the construction to be completed in a factory setting resulting in reduced site fabrication activities and cost. These advanced reactors also require a smaller footprint. They can be deployed much more rapidly in "packs" or groups of reactors, which allows additional reactors to be added as the need arises. Finally, these smaller reactors employ air cooling systems and use far less water than reactors that use cooling water from a river, lake, or ocean.*

Mr. Chodak explained the timing.

> *The Nuclear Regulatory Commission (NRC) has completed the technical review of one SMR design from NuScale and is currently reviewing a micro reactor application from Oklo. Several other vendors are expected to submit their designs for NRC review in the next few years. NRC's current regulatory framework and review processes are oriented toward light water reactors like the plants we*

[24] https://www.energy.senate.gov/services/files/6162D631-BE98-4929-8599-2671A09EA368

> *operate today. The NRC is currently assessing their processes to complete technical reviews and to issue licenses for nonlight water reactors. Establishing an efficient and timely process for licensing advanced reactors is essential to enabling nuclear power to support decarbonization of our economy. Individual states also have a role in the licensing of new reactors via environmental reviews, water rights and other regulatory constructs. The first SMRs are expected to be placed in service in the 2027-2029 time frame. NuScale, TerraPower, and X-energy are working with federal and state authorities for design certification and combined operating licenses, and with government and private entities for financing.*

Mr. Chodak also noted that SMR's may be integrally necessary to produce green hydrogen in an economic manner.

> *SMRs can be located near hydrogen production facilities and transport hubs. This makes SMRs an ideal partner to large oil and gas companies that will transition to hydrogen production and transportation. (The Royal Dutch Shell chief scientist spoke to the NEI board of directors in October and explained that in the future, Shell will rely on SMRs and renewables to produce hydrogen as part of repurposing storage and transport infrastructure for the transport of hydrogen.)*

Q. DO YOU BELIEVE THAT THERE WILL BE GREATER CLARITY AS TO WHAT FUTURE RESOURCES SHOULD AND COULD BE BETWEEN 2028 AND 2040?

A. Yes, and it appears Mr. Chodak does as well. A number of SMR's are expected to be placed in service by the end of this decade. If all goes according to plan, commercial penetration will increase in the 2030s. SMR's could also be a key to producing green hydrogen through electrolysis which will determine the viability of hydrogen conversions of gas plants.

V. CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. After a review of the filing and given my knowledge of the industry, I conclude that the funding ELG compliance costs is meritorious for a number of reasons including:

- There is a significant cost associated with replacing 2,100 MW of capacity in a relatively short time period;

- There is not a significant cost for compliance with the ELG rule;
- The analysis provided by the Company does not reflect emerging technologies that could be realized by a deferring new resource commitments at this time;
- The analysis provided by the Company does not reflect AEP's corporate decarbonization strategy;
- The analysis does not reflect the current disruptions in the global energy market, as well as supply chain delays that are proving problematic; and
- APCo Virginia ratepayers will be deprived of Amos and Mountaineer generation after 2028 as ELG compliance will be proceeding regardless of this Commission's decision.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission approve cost recovery for ELG compliance.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. I reserve the right to update my testimony should new information become available.

22072024

ATTACHMENT I

RESUME OF EMILY S. MEDINE

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 on utility fuel procurement practices and coal contract disputes. The types of projects in which she is involved are described below:

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 Puerto Rico Electric Power Authority, Appalachian Power (2006, 2007, 2015, 2016, 2018, 2021, and 2022) and Monongahela Power (2007, 2015, 2016, 2018, and 2021) on behalf of the Consumer Advocate of the State of West Virginia, Tucson Electric Power in 2007/2008 and 2012 and Arizona Public Service in 2021 on behalf of the Arizona Corporation Commission,.

Procurement

Ms. Medine develops and implements fuel procurement strategies for U.S. and foreign coal and petroleum coke consumers. Fuel procurement assistance has ranged from determining an appropriate strategy to soliciting bids and negotiating purchase agreements. In recent years, Ms. Medine has worked on natural gas and REC procurement evaluations.

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. 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. Ms. Medine was engaged by the Department of Justice in the Alpha Natural Resource and Arch Coal bankruptcies.

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.

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) and on methodology and modelling.

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. Ms. Medine managed the sale of a number of distress assets including JWR Resources, Piney Creek Resources, and Rhino Resources.

Market Strategy Development

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

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.

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 fuel procurement issues and arbitration proceedings on contract disputes and damages. 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. Ms. Medine worked as a Research Assistant at Brookhaven National Laboratory while she attended graduate school.

EDUCATION

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

CERTIFICATE OF SERVICE

I hereby certify that on July 29, 2022, a copy of the foregoing Notice of Participation as Respondent was served upon all parties and/or counsel of record in this proceeding by electronic mail or hand delivery, addressed as follows:

Noelle J. Coates, Esq.
American Electric Power Service Corporation
3 James Center
1051 East Cary Street, Suite 1100
Richmond, Virginia 23219
njcoates@aep.com

James R. Bacha, Esq.
American Electric Power Service Corporation
1 Riverside Plaza
Columbus, Ohio 43215
jrbacha@aep.com

Daniel Summerlin
Woods Rogers PLC
10 S. Jefferson St., Suite 1800
Roanoke, Virginia 24011
summerlin@woodsrogers.com

April M. Rogers
Woods Rogers PLC
Riverfront Plaza, West Tower
951 East Byrd Street
Richmond, Virginia 23219
summerlin@woodsrogers.com

C. Meade Browder, Jr., Esq.
C. Mitchell Burton, Jr., Esq.
Office of the Attorney General
Division of Consumer Counsel
202 N. 9th Street, Floor 8
Richmond, Virginia 23219
mbrowder@oag.state.va.us
cburtonjr@aog.state.va.us

Frederick D. Ochsenhirt, Esq.
C. Austin Skeens, Esq.
Office of General Counsel
State Corporation Commission
Tyler Building – 10th Floor
1300 East Main Street
Richmond, Virginia 23219
Frederick.Ochsenhirt@scc.virginia.gov
Austin.Skeens@scc.virginia.gov

Evan D. Johns, Esq.
Appalachian Mountain Advocates
PO Box 507
Lewisburg, West Virginia 24901
ejohns@appalmad.org

Dorothy E. Jaffe, Esq.
The Sierra Club
50 F Street Northwest, Eighth Floor
Washington, District of Columbia 20001
dori.jaffe@sierraclub.org

Nathan Benefardo, Esq.
William C. Cleveland, Esq.
Josephus Allmond, Esq.
Southern Environmental Law Center
120 Garrett Street, Suite 400
Charlottesville, Virginia 22902
nbenforado@selcva.org
wcleveland@selcva.org
jallmond@selcva.org

Jacob C. Altmeyer, Esq., *Counsel for West Virginia Coal Association, Inc.*

{P0340062.1}