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APPALACHIAN POWER

An AEP Company

BOUNDLESS ENERGY

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April 19, 2022

Via Hand Delivery
Karen Buckley
Acting Executive Secretary
Public Service Commission of West Virginia
201 Brooks St.
Charleston, WV 25301

Re: **Case No.** 22-0393-E-ENEC
Appalachian Power Company and Wheeling Power Company
Petition to Initiate the Annual Review and to Update the ENEC Rates Currently in Effect

Dear Ms. Buckley:

On behalf of Appalachian Power Company and Wheeling Power Company (together, "the Companies"), I file herewith the original and twelve (12) copies of the above-referenced filing, consisting of a Petition and the direct testimony and exhibits of the following witnesses for the Companies: Randall R. Short, Clinton M. Stutler, Jeffrey C. Dial, Shelli A. Sloan, Michael J. Zwick, Jason M. Stegall, Ruby A. Greenhowe, and John J. Scalzo.

Certain of the exhibits to the testimony of Company witnesses Dial, Sloan, Zwick, and Stegall contain confidential information. In addition to the original and twelve copies of the redacted public versions of those documents, three (3) copies of the confidential versions of those documents are being filed, under seal, with a cover letter attached to the outside of the sealed envelope containing them. Within one week of this filing, the Companies will file a Motion for Protective Treatment. The Companies request that the Executive Secretary's office take measures to ensure that the materials filed under seal are protected from public access and accorded protected status pending the Commission's ruling on that motion.

Thank you for your attention to this matter. Please note my appearance, as well as the appearance of my co-counsel William C. Porth and Anne C. Blankenship, and include us on all future correspondence.

Sincerely,

Keith D. Fisher (WV State Bar #11346)
Counsel for Appalachian Power Company and Wheeling Power Company

Enclosures

04:28 PM APR 19 2022 EXEC

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

CASE NO. 22-0393-E-ENEC

APPALACHIAN POWER COMPANY and
WHEELING POWER COMPANY,
public utilities.

Petition to Initiate the Annual Review and to Update the ENEC Rates Currently in Effect

PETITION

COME NOW Appalachian Power Company ("APCo") and Wheeling Power Company ("WPCo") (jointly "the Companies"), by counsel, and respectfully submit their 2022 Expanded Net Energy Cost ("ENEC") filing with the Commission. In support of this Petition, the Companies state as follows:

1. The Petitioners are APCo and WPCo. APCo is incorporated in the Commonwealth of Virginia and is authorized to do business in West Virginia. WPCo is incorporated in West Virginia. The Companies are public utilities providing electric service to customers within 25 counties of West Virginia. The Companies' principal office in West Virginia is located at 500 Lee Street East, Charleston, WV 25301.

2. In this proceeding, the Companies are proposing that their ENEC rates be increased so as to produce approximately an additional $297 million in annual ENEC revenues in order to achieve an appropriate balance between ENEC costs and revenues.

3. The Companies' proposal is based on the traditional forecast period of September 1, 2022 through August 31, 2023, and the actual review period under-recovery balance with the following adjustments:

a. recovery of deferred COVID-19 expenses from March 1, 2021 through February 28, 2022;

b. a refund of the remaining balance of unprotected accumulated deferred federal income tax ("ADFIT") to customers; and

c. a reduction of the ENEC under-recovery balance due to the termination of the Felman Production, LLC special contract.

4. The Companies address issues that have been raised by the Commission in recent ENEC orders, including dislocations in the coal supply market that have produced high prices and limited availability of steam coal, the ability of the Companies to achiever higher capacity factors at their coal-fired power plants, and the commitments of the Companies to purchase power under various long-standing contracts.

5. The Companies are proposing, because of the current volatile energy markets, either that ENEC rates be examined more frequently, perhaps every six months, or that the projected change in the ENEC balance during the six month "dead" period[1] be included in the ENEC rates going forward in order to alleviate sending incorrect price signals to customers and to decrease the burden on the Companies to carry deferred balances for longer periods.

6. Finally, the Companies continue to seek needed clarification from the Commission about the dual imperatives of increasing the capacity factors of their coal-fired power plants and relying on economic dispatch to obtain economically-priced power for their

[1] As explained in more detail in Mr. Short's direct testimony, the traditional ENEC review period used in this proceeding leaves out the six-month period from March 1 through August 31 and is not reflected in either the actual review period ending February 28 or in the forecast period beginning September 1. Any under- or over-recoveries during this "dead" period roll over into the following year's ENEC and are not reflected in rates for eighteen months.

customers and how the Commission wants them to deal with the conflicts between these two imperatives.

7. The matters embraced by this filing are particularized and supported by the direct testimony and exhibits of eight witnesses for the Companies: Randall R. Short, Clinton M. Stutler, Jeffrey C. Dial, Shelli A. Sloan, Michael J. Zwick, Jason M. Stegall, Ruby A. Greenhowe, and John J. Scalzo.

WHEREFORE, the Companies respectfully request that the Commission enter an Order approving their Petition, adopting the Companies' proposals as set forth in this proceeding, and awarding such other and further relief as appropriate.

Respectfully submitted this 19th day of April, 2022.

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY

By Counsel,

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VERIFICATION

STATE OF WEST VIRGINIA,)

COUNTY OF KANAWHA, TO-WIT:)

John J. Scalzo, Vice President – Regulatory Services and Finance for Appalachian Power Company and Wheeling Power Company, after being duly sworn, states upon his information and belief that the facts and allegations contained in the foregoing "Petition" are true and correct.

John J. Scalzo

Taken, subscribed and sworn to before me on the 19th day of April, 2022.

My commission expires: October 2, 2024.

Dorothy E. Philyaw
Notary Public

(SEAL)

OFFICIAL SEAL
NOTARY PUBLIC
STATE OF WEST VIRGINIA
Dorothy E. Philyaw
Appalachian Power Company
PO Box 1986
Charleston, WV 25327-1986
My Commission Expires October 02, 2024

BEFORE THE
PUBLIC SERVICE COMMISSION OF WEST VIRGINIA
CASE NO. 22-______________

IN THE MATTER OF

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY

INDEX OF
TESTIMONY AND EXHIBITS

RANDALL R. SHORT
CLINTON M. STUTLER
JEFFREY C. DIAL
SHELLI A. SLOAN
MICHAEL J. ZWICK
JASON M. STEGALL
RUBY A. GREENHOWE
JOHN SCALZO

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
DIRECT TESTIMONY
OF
RANDALL R. SHORT

DIRECT TESTIMONY OF
RANDALL R. SHORT
ON BEHALF OF APPALACHIAN POWER COMPANY AND WHEELING POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF WEST VIRGINIA IN CASE NO. 22-__________

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

A. My name is Randall R. Short. I am employed by Appalachian Power Company ("APCo") as Director of Regulatory Services for West Virginia. My business address is 500 Lee Street, East, Charleston, West Virginia.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I graduated with a Bachelor of Science Degree in Management and a Masters of Business Administration, both from Marshall University. I joined APCo as Director of Regulatory Services in October 2020. Prior to that, nearly my entire professional career was in utility regulation with the Public Service Commission of West Virginia, where I began as a Utility Analyst with the Consumer Advocate Division in 1993 and progressed through several steps to being an advisor to the Commission and eventually to Deputy Director and Interim Director of the Utilities Division before my retirement from the Commission in September 2020.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS DIRECTOR OF REGULATORY SERVICES FOR WEST VIRGINIA.

A. My duties include the supervision and direction of the Regulatory Services Department, which has the responsibility for rate and regulatory matters affecting APCo's West Virginia jurisdiction and Wheeling Power Company ("WPCo"). Both APCo and WPCo are operating company subsidiaries of American Electric Power Company, Inc.

Q. FOR WHOM ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of both APCo and WPCo (collectively, the "Companies").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, I have testified numerous times before the Commission on a variety of issues across the spectrum of utilities regulated by the Commission. I most recently provided testimony on behalf of the Companies in Case No. 22-0304-E-P.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to:

1. Provide a list of the Companies' witnesses (except for myself) and a brief description of the subject matters addressed in their testimony;
2. Provide a summary of the 2021 ENEC case and the status of the reopened proceeding;
3. Request that the Commission approve an ENEC increase of approximately $297 million to achieve an appropriate balance between ENEC costs and revenues;
4. Discuss the ENEC review period in this ENEC proceeding;
5. Describe the starting position for this year's ENEC proceeding;
6. Explain the Companies' ENEC proposal in this proceeding;
7. Explain the COVID 19 and unprotected ADFIT true-up amounts included in the filing;
8. Discuss purchased power expenses in light of the Commission's September 2, 2021 and March 2, 2022 Orders in Case No. 21-0339-E-ENEC.

Q. PLEASE PROVIDE A LIST OF THE COMPANIES' OTHER WITNESSES AND A BRIEF DESCRIPTION OF THE SUBJECT MATTERS ON WHICH THEY ARE TESTIFYING.

A. The Companies offer the testimony of the following seven witnesses on the following matters:

- **Clinton M. Stutler**, Natural Gas and Fuel Oil Manager, provides a description of the Companies' natural gas-fired plants, an overview of the natural gas market from January 2020 through March 2022, the natural gas delivery forecast for the twelve months ending August 31, 2023, the Companies' natural gas procurement and transportation strategies and agreements, the mitigation of natural gas volatility and financial hedging, the exemption report for natural gas transactions, and the reasonableness of the Companies' actual and projected natural gas costs.
- **Jeffrey C. Dial**, Director – Coal, Transportation, and Reagent Procurement, discusses the Companies' coal inventory positions, the recent volatility in the coal market, the limitations on the Companies' ability to utilize their coal-fired generation at higher capacity factors, the exemption report for coal transactions, and the reasonableness of the Companies' actual and projected coal costs.
- **Shelli A. Sloan**, Director – Financial Support and Special Projects, provides the Companies' forecast of the ENEC for the twelve-month period ending August 31, 2023, the forecast of the Expanded Net Energy Requirement for the forecast period, the summary of the sources and uses of energy for the forecast period, and unit specific data for the forecast period.
- **Michael J. Zwick**, Vice President of Generating Assets, provides March 2021 through February 2022 information about the Companies' fossil-fueled generating fleet, the need for proper maintenance of that fleet, discussion of Net Capacity Factor and Equivalent Availability Factor, and the types of events that impact these generating statistics.

- **Jason M. Stegall**, Manager - Regulatory Pricing and Analysis, discusses the Companies' participation in the PJM market, PJM's role in determining which generation units are dispatched, the 2021 energy market and the effects of increased energy prices, and the projected capacity factors for the Companies' coal-fired generating units.
- **Ruby A. Greenhowe**, Regulatory Consultant Principal – Provides an overview of the Companies' ENEC recovery position and explains the calculation of jurisdictional and class allocation factors and ENEC rate factors.
- **John J. Scalzo**, Vice President Regulatory and Finance - Explains the Companies' need for further clarification regarding the Commission's directive to maximize the Companies' use of their coal-fired power plants.

Q. WHAT ARE THE COMPANIES PROPOSING IN THIS PROCEEDING?

A. The Companies propose to use the customary ENEC ratemaking mechanisms to increase the Companies' ENEC rates to produce needed additional revenues of approximately $297 million effective September 1, 2022.

Q. WHAT IS THE REVIEW PERIOD IN THIS ENEC PROCEEDING?

A. In the Companies' last ENEC proceeding, Case No. 21-0339-E-ENEC, the Commission established new ENEC rates that would remain in effect for the period September 2, 2021 to August 31, 2022.[1] Consequently, the Companies are using as a review period the twelve months ending February 28, 2022.

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[1]ENEC rate changes typically are effective on the first day of the month. On August 31, 2021, in Case 21-0339-E-ENEC, the Commission issued an order that the existing rates should remain in effect until further Commission order. On September 2, 2021, the Commission issued an order approving new ENEC rates effective for all service rendered on and after September 2, 2021.

Q. PLEASE PROVIDE A SUMMARY OF THE SEPTEMBER 2, 2021 ENEC ORDER, SUBSEQUENT FILINGS BY THE COMPANIES, AND THE STATUS OF THE REOPENED PROCEEDING.

A. In their 2021 ENEC filing, the Companies sought an increase in their ENEC increment of approximately $73 million. This included $55 million in under-recovery, $32 million of which was deferred from Case No. 20-0262-E-ENEC. The Companies also sought an increase of $18 million for projected ENEC expenses for the forecast period. The Commission's September 2, 2021 Order reduced the Companies' projected West Virginia jurisdictional ENEC by $66.7 million, stating that the Companies' projections included significant amounts of purchased power and that the public's interest is better served by the Companies focusing on maximizing generation from its owned power plants. The Order further stated that the significant amounts of purchased power could be prudent but the Companies will have the burden of proof to demonstrate that actual costs are reasonable, prudently incurred, and not contrary to the public interest in West Virginia. On September 13, 2021, the Companies filed a Petition for Reconsideration or Clarification of the September 2, 2021 Order.

On March 2, 2022 the Commission issued an order in Case No. 21-0339-E-ENEC denying in part and granting in part the Petition for Reconsideration or Clarification with a correction for the reduced cost of purchased power by WPCo and an allowance for additional handling costs on the incremental increase in generation which the Commission had projected. Based on those factors, the Commission increased the previously authorized ENEC revenue requirements by $31.4 million, effective immediately. The Commission also expressed concern about under-recovery levels booked by the Companies and ordered the reopening of the evidentiary record of the

2021 ENEC proceeding to determine what is currently happening in the PJM markets and what is happening with the ability of the Companies to utilize their coal-fired power plants.

The Companies were ordered to file information as described in the March 2, 2022 Order by March 14, 2022. The Companies complied, filing the Supplemental testimony of six witnesses and reporting that the under-recovery had grown to $216 million as of February 28, 2022. That under-recovery, along with projections indicating a need to increase rates by an additional $93 million to reflect higher ENEC expenses for the twelve-month forecast period of March 1, 2022 through February 28, 2023, would require a total change in ENEC rates of approximately $310 million for the twelve-month period. The Commission stated that any rate change resulting from the reopened proceeding may be required as soon as May 1, 2022 and should be considered as interim rates subject to future true-up. In an effort to keep the under-recovery from increasing to unmanageable levels but also to moderate the rate impact on customers, the Companies limited their request to an increase of $155 million, half of the justifiable increase. In conjunction with that reduced immediate request, the Companies recommended the Commission adjust the Companies' ENEC rates every six months, for the foreseeable future, given the highly volatile fuel and energy markets.

The Commission authorized the other parties to the 2021 ENEC proceeding to file comments by March 21, 2022. The Staff, WVEUG, and the CAD filed comments and the CAD also filed the testimony of Emily R. Medine. An evidentiary hearing was held on March 23, 2022. While the Commission stated in the March 2, 2022 Order that any change in rates may be required as early as May 1, the Commission to date has not issued any further order and the Companies have no way of knowing what change in rates, if any, may be ordered. Therefore, the Companies file this ENEC case without making any assumptions or adjustments based upon possible future developments in the 2021 ENEC proceeding. The requested change in ENEC rates in this filing reflects: (1) the under-recovery balance of $212.7 million as of February 28, 2022; (2) the March 2, 2022 increase in ENEC rates of $31.4 million; and (3) the projected increase in ENEC costs of $83.9 million for the forecast period of September 1, 2022 through August 31, 2023. If the Commission issues an order in the 2021 ENEC case implementing a change in ENEC rates to go into effect before September 1, 2022, the Companies will adjust their ENEC request in the current case accordingly.

Q. HOW IS THIS ENEC REQUEST DIFFERENT FROM THE FILING MADE BY THE COMPANIES ON MARCH 14, 2022 IN THE REOPENED PROCEEDING?

A. The Companies' March 14, 2022 filing reflected an updated forecast for the six-month period ending August 31, 2022 with actuals updated for the six months ending February 28, 2022, while the instant filing reflects the traditional forecast period September 1, 2022 through August 30, 2023. The reopened filing stated the under-recovery balance at February 28, 2022. The instant filing uses the same time period for the review period but additionally reflects adjustments related to COVID-19 deferrals and the flow back of a regulatory liability.

Q. HAVE THE COMPANIES CONTINUED DEFERRING COVID-19 COSTS?

A. The Commission's General Order No. 262.4, issued May 15, 2020, provided that privately owned utilities subject to regulation by the Commission may record a deferral of additional, extraordinary costs directly related to complying with the various government shut-down orders and COVID-19 precautions, including impacts on uncollectible expense and minimum demand charges. In the 2021 ENEC, the

Commission granted the Companies' requested recovery of $2.3 million in deferred COVID-19 expensed incurred through February 28, 2021. The Companies continued deferring additional COVID-19 expenses from March 1, 2021 through February 28, 2022, the end of the review period.

Q. WHAT COSTS RELATED TO COVID-19 ARE THE COMPANIES SEEKING TO RECOVER?

A. The Companies request recovery of $619,000 of COVID-19 costs deferred during the twelve months ended February 28, 2022, related to the continued implementation of social distancing requirements, the facilitation of working remotely, cleaning and disinfecting supplies and services, personal protection equipment, and printed COVID-19 safety materials. While the Commission has not issued an order discontinuing the deferral of COVID-19 expenses, the Companies stopped deferring as of March 1, 2022.

Q. ARE THESE COSTS SEPARATE FROM THE $2.3 MILLION OF COVID-19 COSTS APPROVED BY THE COMMISSION FOR RECOVERY IN CASE NO. 21-0339-E-ENEC?

A. Yes. The Companies continue to separately amortize $2.3 million of COVID-19 costs previously incurred and deferred through February 2021. As of February 28, 2022, the Companies have $1.2 million of remaining unamortized COVID-19 costs that were approved for recovery by the Commission in the 2021 ENEC. The Companies will fully amortize and recover this $1.2 million balance at the end of August 2022.

Q. AS PART OF THE STIPULATION OF CASE NO. 20-0262-E-ENEC, THE COMPANIES AGREED TO FLOW EXCESS UNPROTECTED ACCUMULATED DEFERRED FEDERAL INCOME TAX ("ADFIT") BALANCES BACK TO CUSTOMERS THROUGH THE END OF JUNE 2021 VIA THE TAX REFORM

RIDER ("TRR"). THE PARTIES ALSO AGREED THAT, IN FUTURE ENEC CASES, THE COMPANIES WILL TRUE-UP ANY OVER- OR UNDER-CREDITED UNPROTECTED ADFIT FLOWBACKS. WHAT IS THE STATUS OF THE ADFIT FLOWBACK?

A. After the conclusion of the TRR in August 2021, the remaining balance of the unprotected ADFIT due to customers is $4,108,024. APCo has an unprotected ADFIT balance of ($14,065,789) and WPCo has an unprotected ADFIT balance of $9,957,765, resulting in the net remaining balance of ($4.1 million).

Q. HOW DO THE COMPANIES PROPOSE TO REFUND THE REMAINING BALANCE OF UNPROTECTED ADFIT?

A. The Companies propose to net the entire balance of unprotected ADFIT on APCo's financial records. The net ($4.1 million) will be included in the ENEC balance and will be amortized over the twelve month period to the benefit of customers.

Q. DID THE COMPANIES MAKE AN ADJUSTMENT TO THE ENEC BALANCE TO REFLECT THE TERMINATION OF THE FELMAN SPECIAL CONTRACT?

A. Yes. On September 23, 2021, Felman Production, LLC ("Felman") filed a petition to terminate its special contract with APCo that was previously approved in Case No. 13-1325-E-PC, and requested expedited treatment. The special contract created a bank that would reflect adjustments to the prices paid for power by Felman based on changes in commodity indices and the market price for silicomanganese. On November 2, 2021, the Commission approved termination of the special contract, effective September 1, 2021. As a result, the remaining positive bank balance of $10.6 million was credited to the ENEC, reducing the ENEC under-recovery balance by that amount.

Q. ARE THE COMPANIES SEEKING COST RECOVERY OF ELECTRICITY PURCHASED THROUGH CERTAIN CONTRACTUAL COMMITMENTS?

A. Yes. The Companies are seeking recovery of the costs associated with several contractual commitments, including with the Ohio Valley Electric Corporation ("OVEC") and under several purchased power agreements ("PPAs") that APCo has entered into over the past approximately fifteen years. For example, in Case Nos. 07-1731-E-PC and 07-1848-E-PC, APCo sought approval for contracts to purchase, under twenty-year contracts, power produced by the Fowler Ridge wind project and the Camp Grove wind project, respectively. In those filings, APCo represented that the projects were the winning bids resulting from a competitive solicitation and that the contract terms and purchase prices for each project were just and reasonable. A Stipulation was filed by the parties to the cases agreeing that APCo may seek recovery of the expenses incurred under the contracts as part of APCo's annual ENEC proceeding. In the December 21, 2007 Order approving the Joint Stipulation and Agreement for Settlement, the Commission stated, "Given the issues surrounding wind power generation, the tremendous uncertainty regarding greenhouse gas emissions, the cost of environmental retrofits, and the uncertain results of demand side or energy efficiency programs, it is reasonable for APCo to commit to some long-term purchases of renewable wind generation for it mix of generation." (Order at 4)

Q. DID THE COMMISSION COMMENT ON THESE CONTRACTUAL COMMITMENTS IN ITS MARCH 2, 2022 ORDER?

A. Yes, it did. In their September 13, 2021 Petition for Reconsideration or Clarification, the Companies argued that it was an error for the Commission to conclude that both non-discretionary purchases and market purchases of power could be displaced by increasing generation from the Companies' owned plants and that the costs of purchased power under the contractual commitments were approved for recovery in previous ENEC cases. The Commission stated in its March 2, 2022 Order, "Because the Companies have entered into a contract for certain costs, and labels those costs as non-discretionary, does not mean that this Commission must send a signal at this time that it considers those costs reasonable…." The Order also stated, "the Commission must be free to decide issues of cost recovery anew, based on current circumstances, even when those costs are incurred under long-term contracts and previous purchases under those contracts had been approved for cost recovery in the past." (Order at 5)

The Companies fully understand the Commission's prerogatives with respect to cost recovery. But they also understand the Commission's obligation to judge the prudence of a public utility's decisions on the basis of the circumstances existing and the information available at the time the decisions were made.

Q. ARE THE COMPANIES LIMITING THE DISPATCHING OF THEIR COAL PLANTS TO ACHIEVE A DECARBONIZATION GOAL OF THE COMPANIES OR THEIR PARENT COMPANY?

A. No. The Companies are not limiting the dispatching of any of their internal generation resources to achieve any decarbonization goal. As the Commission knows, PJM evaluates the cost of the various generation resources available to meet the needs of their members and calls upon those resources to operate based primarily on economics, starting with the least expensive resources and moving up progressively through more expensive resources. The Companies rely on the economics of their internal generation resources and availability of fuel recently to determine the dispatching of these resources. Company witness Stegall explains how the Companies bid their generation resources into

PJM. In its March 2, 2022 Order, however, the Commission stated its intent to require the Companies to follow a power supply policy to maximize their use of fossil-fuel generation that is cheaper than purchased power. Company witness Scalzo further explains the Companies' need for further clarification regarding the Commission's directive.

Q. DO THE COMPANIES HAVE ANY OTHER CONCERNS AT THIS TIME REGARDING THE ENEC PROCESS?

A. Yes. Under the current practice, the Companies' ENEC filing reflects actual under- or over-recovery ENEC balances at February 28 as well as a request for any changes necessary to match current ENEC rates with the projected ENEC costs in the forecast for the period September 1 through the following August 31. This timing leaves the six-month period from March 1 thought August 31 reflected in neither the actual review period ended February 28 or in the forecast period beginning September 1. Any under- or over-recoveries during this "dead" period roll over into the following year's ENEC, potentially exacerbating those balances. Especially during the current volatile energy markets, that six-month period needs to be reflected in rates sooner than eighteen months later, which currently produces incorrect price signals to customers and an increased burden on the Companies to carry deferred balances for longer periods. As previously suggested, a more frequent examination of the ENEC rates would help alleviate this problem. Another alternative would be to include the projected change in the ENEC balance during the dead period into the ENEC rates going forward.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
DIRECT TESTIMONY
OF
CLINTON M. STUTLER

DIRECT TESTIMONY OF
CLINTON M. STUTLER
ON BEHALF OF APPALACHIAN POWER COMPANY AND
WHEELING POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA IN CASE NO. 22-____________________

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

A. My name is Clinton M. Stutler, and I am employed by American Electric Power Service Corporation ("AEPSC"), a subsidiary of American Electric Power Company, Inc. ("AEP") in the regulated Commercial Operations organization as the Natural Gas and Fuel Oil Manager. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I earned a Bachelor of Science in Business Administration degree, with a major in Transportation & Logistics and Marketing, from The Ohio State University in 2002, and a Master's degree in Business Administration from Bowling Green State University in 2007.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. I have twenty years of energy–industry experience in fuel procurement, logistics, marketing, scheduling, and transportation. My professional background began in 2002 as a Scheduler with Marathon Petroleum Company. In 2008, I joined AEPSC in the Fuel, Emissions, and Logistics organization as a Coal Buyer, with responsibilities for the procurement of coal for Ohio Power Company. In 2014, I joined AEP Generation Resources, with responsibilities for purchasing natural gas, coal, urea, and fuel oil, in addition to marketing fly ash and flue gas desulfurization gypsum. In 2016, I accepted a position in the regulated Commercial Operations organization as a Coal Buyer and became responsible for the procurement of coal for Appalachian Power Company

("APCo"), Kentucky Power Company ("KPCo"), and Southwestern Electric Power Company ("SWEPCO"). On May 4, 2018, I was promoted to my current position and became responsible for the procurement and delivery of natural gas and fuel oil to AEP's regulated generating fleet.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS NATURAL GAS AND FUEL OIL MANAGER.

A. I am responsible for the procurement and delivery of natural gas and fuel oil to AEP's regulated generating fleet, which includes regulated power plants owned and/or operated by APCo, Wheeling Power Company ("WPCo"), KPCo, Indiana & Michigan Power Company ("I&M"), Public Service Company of Oklahoma ("PSO"), and SWEPCO.

Q. FOR WHOM ARE YOU PROVIDING TESTIMONY IN THIS PROCEEDING?

A. I am providing testimony on behalf of both APCo and WPCo (together, the "Companies").

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE ANY REGULATORY AGENCIES?

A. Yes. I have submitted testimony and testified on behalf of APCo and WPCo before the Public Service Commission of West Virginia, before the Oklahoma Corporation Commission on behalf of PSO and before the Kentucky Public Service Commission on behalf of KPCo. Furthermore, I have filed testimony before the Public Utility Commission of Texas on behalf of SWEPCO and before the State Corporation Commission of Virginia on behalf of APCo.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to:

1) Provide a general description of APCo's natural gas-fired plants;
2) Provide an overview of the natural gas market from January 2020 through March 2022, in which APCo procured natural gas;
3) Provide the natural gas delivery forecast for the twelve months ending August 31, 2023 ("Forecast Period");
4) Discuss APCo's natural gas procurement strategy and APCo's natural gas supply and transportation agreements;
5) Describe how APCo mitigates natural gas price volatility and why the implementation of a financial hedging program would not necessarily lead to lower natural gas costs;
6) Provide the exemption report for natural gas transactions from January 1, 2021 through February 28, 2022; and
7) Discuss the reasonableness of APCo's actual and projected natural gas costs.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibits:

- Company Exhibit CMS-D1 details by month the forecasted delivered cost of natural gas for the Forecast Period;
- Company Exhibit CMS-D2 summarizes the projected versus actual delivered cost of natural gas for the twelve months ended February 28, 2022; and
- Company Exhibit CMS-D3 is the exemption report for natural gas transactions.

NATURAL GAS FIRED PLANTS

Q. WHAT NATURAL GAS-FIRED PLANTS ARE INCLUDED IN APCO's GENERATING FLEET?

A. APCo currently has three natural gas-fired plants in its generating fleet, including the Clinch River Plant ("Clinch River"), the Dresden Plant ("Dresden"), and the Ceredo Plant ("Ceredo").

Clinch River is a two-unit natural gas-fired generating facility located in Russell County, Virginia with a combined nominal capacity rating for Units 1 and 2 of 465 Megawatts ("MW"). The coal-to-gas conversion of Unit 1 was completed in March 2016, and the coal-to-gas conversion of Unit 2 was completed in April 2016. Clinch River, which typically operates during periods of peak demand, receives its fuel supply from a natural gas pipeline constructed by Appalachian Natural Gas Distribution Company, a Virginia corporation.

Dresden, a 611 MW baseload natural gas-fired combined-cycle facility, which began commercial operation on January 31, 2012, is located near the Muskingum River in Dresden, Ohio. Dresden is a "2-on-1" combined-cycle plant, meaning it is equipped with two gas turbines and two heat recovery steam generators. The steam from these generators then feeds one steam turbine to provide additional electricity. Combined-cycle plants generate more efficiently and consume less fuel per kilowatt-hour of output than conventional simple-cycle plants.

Ceredo is a 516 MW natural gas-fired simple-cycle power plant that began commercial operation in 2001 and is located near Ceredo, West Virginia. With a natural gas simple-cycle power plant, natural gas powers a combustion turbine, which is connected directly to a generator that produces electricity. Ceredo ramps up quickly and operates as a peaking plant and is utilized when electricity demand is high.

MARKET OVERVIEW

Q. PLEASE PROVIDE AN OVERVIEW OF THE NATURAL GAS MARKET FOR THE PAST TWO YEARS.

A. During the first half of calendar year 2020, the natural gas market was heavily influenced by mild winter weather and the COVID-19 pandemic. These two factors caused noticeable decreases in both domestic and global demand for natural gas, causing extremely low natural gas prices. Prompt month New York Mercantile Exchange ("NYMEX") pricing settled below $2.00 per MMBtu from February 2020 through August 2020. To add perspective, dating back to calendar year 2014, there were only a total of four months where the prompt month NYMEX price settled below $2.00 per MMBtu. Due to very low demand and pricing, producers were forced to scale back on natural gas production.

In the second half of calendar year 2020, as the global economy began to recover from the COVID-19 pandemic, the market became somewhat apprehensive regarding the lack of natural gas production. Many analysts were of the opinion that a resurgence of export demand and normal winter weather could create a rather tight market in the winter and subsequent months. In response, the NYMEX forward curve started to become stronger and approached the $3.00 per MMBtu mark in the fourth quarter of 2020. A mild October 2020 and November 2020 moderated forward prices, but as the global economy began to recover, liquefied natural gas ("LNG") export demand was robust for the entire month of December 2020, continuing into 2021.

In January 2021, U.S. natural gas storage began the year at a surplus when compared to the five-year average. However, with domestic natural gas production continuing to lag, coupled with increased demand, aggressive withdrawals from storage began to erode the storage surplus. By the end of February 2021, U.S. natural gas storage was now at a deficit when compared to the five-year average. Even with a few spot market price spikes due to cold weather events, as well as several massive storage withdrawals, prompt month NYMEX settlement pricing remained relatively low throughout the winter and spring, staying under $3.00 per MMBtu.

In the second half of 2021, the market began to further recognize that the natural gas supply and demand balance would remain tight for the foreseeable future. Continued strong demand and the lack of natural gas production growth began to spur higher market prices. The July 2021 NYMEX contract settled at $3.617 per MMBtu, which was the highest prompt month settlement price since December 2018.

As the 2021 summer months continued, export demand for LNG continued to be very strong. Global natural gas storage was down significantly, which caused panic-buying (on an international level) in an effort to build inventory ahead of the high-demand winter months. This caused LNG export prices to reach (then) record levels on several occasions. In the domestic market, storage injections were below historical averages. In early September 2021, while the market was still experiencing warm temperatures that boosted demand for electricity, domestic producers had to contend with Hurricane Ida, which shut-in more than 38 Bcf of natural gas production over a period of four weeks. The October 2021 and November 2021 NYMEX contracts settled at $5.841 per MMBtu and $6.202 per MMBtu, respectively.

During the months of November 2021 and December 2021, U.S. natural gas production began to increase. Producers were finally able to justify the economics of ramping up output prior to the heating season in an effort to capture perceived record prices in the approaching winter months. However, the month of December 2021 was mild, with residential and commercial heating demand at its lowest level in six years, which put downward pressure on natural gas prices. This also caused only modest withdrawals from storage, with total storage staying very close to the five-year-average. The January 2022 NYMEX contract settled at $4.024 per MMBtu, which was significantly below the prior three months.

Natural gas market volatility has continued into the first quarter of calendar year 2022. Cold winter temperatures throughout the country resulted in natural gas storage withdrawals which surpassed the five-year average level by twenty-eight percent. At the same time, demand for U.S. LNG exports continue to increase. As a matter of fact, on February 18, 2022 feedgas for U.S. LNG export facilities surged to a new record of approximately 13.4 billion cubic feet. The Russian invasion of Ukraine has added further instability to an already volatile energy market. In early March 2022, global LNG prices spiked close to $60 per MMBtu.

The natural gas market has been impacted by unusual, significant events over the past two years. Such events have thrust the market from one extreme to the other. Differences in forecast output, either compared to actual values or other forecast values can clearly be explained by the market volatility that has been experienced over the past two years.

Q. WHAT EFFECT DID RECENT MARKET CONDITIONS FOR NATURAL GAS HAVE ON THE OPERATION OF APCO's PLANTS?

A. When compared to 2020, total natural gas production in the U.S. increased by approximately 1.8 percent in 2021. However, when comparing the same time period, natural gas production in the Appalachian Basin was much stronger, increasing by 5.6 percent. With abundant supply and the continued lack of pipeline takeaway capacity, APCo's customers continue to benefit from low natural gas prices. All of the natural gas purchased for Dresden was procured at the Eastern Gas, South receipt point, which is located in a shale-rich area on the Eastern Gas Transmission and Storage, Inc. ("EGTS") pipeline. Compared to other receipt points, in 2021 natural gas prices remained low at Eastern Gas, South, but were more volatile than in years past. In the first half of 2021, spot market prices averaged \$2.34 per MMBtu, which included a peak settlement of \$7.875 per MMBtu on February 17, 2021. In the second half of 2021, spot market prices trended upward averaging \$3.76 per MMBtu due to global natural gas demand, weak domestic storage injections and stagnant natural gas production. As a comparison, prices averaged slightly less than \$1.40 per MMBtu at the Eastern Gas, South receipt point in 2020.

Pricing for natural gas that is purchased for Ceredo is similar to Dresden, in terms of it being sourced in a shale-rich area and also benefitting from lower priced supply. However, Clinch River is located farther southeast and is unable to directly benefit from inexpensive Marcellus shale gas due to the plant's proximity to higher demand markets and population centers.

When considering the three plants, 2021 consumption declined by approximately six percent, or about 2.2 million MMBtu, when compared to 2020.

NATURAL GAS DELIVERY FORECAST

Q. ARE YOU SUPPLYING A NATURAL GAS DELIVERY FORECAST FOR THE FORECAST PERIOD?

A. Yes. Please see Company Exhibit CMS-D1, which details by month, the forecasted delivered cost of natural gas for APCo, as used in the forecast sponsored by Company witness Sloan and in the *PLEXOS*® simulation model. The forecasted delivered cost of natural gas shown on Company Exhibit CMS-D1 reflects assumptions made in November 2021 and does not reflect market events and prices since then.

A comparison of forecasted natural gas costs from March 1, 2021 through February 28, 2022, and the actual natural gas costs for the same period can be found in Company Exhibit CMS-D2. During the review period, APCo's actual natural gas costs were approximately 54% higher than the forecast, and the actual cost per MMBtu was approximately 56% higher than the forecast.

NATURAL GAS PROCUREMENT STRATEGY & SUPPLY AND TRANSPORTATION AGREEMENTS

Q. PLEASE DESCRIBE APCO'S NATURAL GAS PROCUREMENT STRATEGY.

A. APCo's natural gas procurement strategy and the practices used to purchase natural gas supplies for APCo discussed below, are separate and distinct from the natural gas delivery forecast provided to the Production Costing Department, as described by Company witness Sloan, to determine the cost of fuel consumed at the gas plants as computed by the *PLEXOS®* simulation model. The natural gas procurement strategy provides reliable fuel at the lowest reasonable delivered cost, considering prompt market prices for energy. The procurement strategy is based on two components: transportation and supply. Natural gas pipeline transportation agreements secure the necessary means to transfer the gas supply from the source to the plant. Gas supply agreements provide the commodity used to fuel the power plant. In order to meet day ahead and real time PJM dispatch requests, APCo needs instantaneous, hourly, and daily flexibility in the delivery flow of natural gas supply.

Due to fluctuating natural gas requirements, APCo relies on both firm and interruptible transportation agreements, as well as daily spot market natural gas purchases. Additionally, at times when APCo expects Dresden to be available nearly every day of the month, APCo will issue requests for proposals to obtain monthly baseload natural gas supply. Daily spot market purchases are typically based on index pricing, while monthly baseload agreements are either based on fixed price offers or first-of-month index pricing. Furthermore, prior to the 2021-2022 winter season, APCo issued two seasonal RFPs seeking fixed price natural gas supply offers spanning multiple months. APCo did not receive any natural gas supply offers in response to either RFP.

The natural gas arrangements utilized by APCo provide the required flexibility necessary to reliably operate APCo's system, while minimizing overall total fuel costs.

Q. WHAT ARE THE PRACTICES USED TO PURCHASE NATURAL GAS SUPPLIES FOR APCO?

A. AEPSC, on behalf of APCo, pursues market purchase opportunities through a competitive bidding program. For daily market purchases, the natural gas buyer receives a forecast from AEPSC's Bid, Offer and Cost Development team each morning and discusses the expected operation and estimated natural gas requirements for APCo's power plants for the current and the following six days. Then, the natural gas buyer gathers market information from the various natural gas market areas and hubs accessible to APCo. The buyer also obtains pricing and volume information from numerous natural gas suppliers, as well as real-time natural gas market data from platforms such as the Intercontinental Exchange ("ICE") to locate and optimize purchases in the spot natural gas market.

Once the buyer analyzes the relevant information, the necessary spot natural gas supplies are purchased from the most economical and reliable sources available at the time. The natural gas buyer then makes the necessary nominations and scheduling arrangements with the transporting pipelines to deliver the natural gas supplies to the power plants and monitors deliveries for each particular gas day. Every afternoon, the natural gas buyer reviews the units that received a day-ahead award from PJM and, depending on the results, makes adjustments through additional purchases or sales, as necessary.

For the months that Dresden is expected to operate daily, the natural gas buyer evaluates the need for seasonal or monthly baseload purchases. Using market information obtained from the suppliers, real-time natural gas market information from the New York Mercantile Exchange ("NYMEX") and ICE, as well as various natural gas publications, decisions are made, whenever possible, to acquire a portion of the forecasted minimum supplies to reduce exposure to potential volatility in the daily, spot natural gas market. If it is determined that purchasing seasonal or monthly baseload supply is reasonable, an RFP will be issued to secure such supplies.

Q. PLEASE DESCRIBE APCO'S NATURAL GAS TRANSPORTATION AGREEMENTS.

A. The Clinch River Plant has an Interruptible Transportation ("IT") agreement, with East Tennessee Natural Gas, LLC ("ETNG") which was executed in 2015. The agreement provides for deliveries of a maximum daily quantity ("MDQ") of 125,000 MMBtu per day to the Clinch River meter at the interconnection of the lateral pipeline owned and operated by Appalachian Natural Gas Distribution Company. In order to manage supply imbalances, APCo has a tariff-based balancing agreement in place with ETNG, which is also referred to as a Load Management (Market Area) Service Agreement ("LMS-MA"). The LMS-MA agreement allows APCo to carry small daily variances on the pipeline throughout the month. At the end of each month, any long or short imbalance is settled with the pipeline at a pre-determined rate as established by ETNG's tariff. Additionally, APCo has a ten-year Firm Transportation ("FT") agreement with

Appalachian Natural Gas Distribution Company to move the needed supplies from the interconnect to the Clinch River Plant.

APCo had a ten-year FT agreement with EGTS that was executed in 2012, with the original terms expiring on January 31, 2022. In August of 2020, APCo and EGTS were successful in negotiating a contract extension with revised terms that go through December 31, 2028. This agreement will continue to provide reliable natural gas deliveries to the Dresden Plant with an MDQ of 109,000 MMBtu per day.

With regard to the Ceredo Plant, APCo has an IT agreement with Columbia Gas Transmission and an FT agreement with Mountaineer Gas Company ("MGC"), the local distribution company. The FT agreement reliably moves needed supplies from the Columbia Gas Transmission pipeline to the plant. This FT agreement also provides flexible banking services allowing the Ceredo units to meet PJM's requests to come online and offline with little notice.

Q. IS RISK ASSESSMENT AN IMPORTANT FACTOR IN NATURAL GAS PROCUREMENT DECISIONS?

A. Yes. APCo considers a supplier's financial status, ability to deliver, and past performance when evaluating its fuel purchase alternatives. This practice is designed to lower the risk and enhance APCo's supply security. Natural gas supplies are only procured from counterparties on APCo's credit approved list.

<u>FINANCIAL AND PHYSICAL NATURAL GAS HEDGING</u>

Q. HAS THE COMPANY ENTERED INTO ANY FINANCIAL NATURAL GAS HEDGES?

A. No.

Q. WHAT IS THE OPINION OF THE COMPANY WITH REGARD TO A FINANCIAL NATURAL GAS HEDGING PROGRAM?

A. While a financial hedging program may decrease fuel price volatility, such transactions have gains, losses and associated costs. If the Company were to engage in a financial hedging program, as opposed to our current approach, customers would likely incur additional cost for options and/or financial futures instruments. Also, there could be some basis risk associated with the financial product and the physical product that the Company would be attempting to hedge. Furthermore, a financial hedge does nothing to improve the reliability of supply or provide the ability to generate electricity during periods of physical supply constraints.

Q. IF NOT THROUGH FINANCIAL HEDGING, HOW DOES THE COMPANY OTHERWISE MANAGE NATURAL GAS PRICE VOLATILITY?

A. The Company's strategy of utilizing seasonal or monthly fixed price baseload natural gas supply contracts to physically hedge a percentage of expected requirements continues to be a prudent strategy. As an example, February 2021 was an extremely volatile month with regard to daily spot prices at the Eastern Gas, South market hub, with prices ranging from $2.085 per MMBtu to $7.875 per MMBtu. Prior to the start of February, APCo participated in Bidweek, which is the specific time each month where market participants transact on prompt month contracts. Subsequent to issuing and evaluating a request for proposal ("RFP"), APCo purchased 20,000 MMBtu of natural gas per day for the month of February at a settlement price of $2.32 per MMBtu. Through this physical hedge, APCo insulated its customers from the volatility experienced in the February 2021 spot market, thus saving its customers more than $550,000 in natural gas supply costs.

EXEMPT NATURAL GAS TRANSACTIONS

Q. DID THE COMPANY ENTER INTO ANY EXEMPT NATURAL GAS TRANSACTIONS?

A. Yes. These transactions are reported on Company Exhibit CMS-D3.

CONCLUSION

Q. ARE APCO'S ACTUAL AND PROJECTED NATURAL GAS COSTS REASONABLE?

A. Yes. The forecasted delivered cost of natural gas shown on Company Exhibit CMS-D1 is reasonable based upon the information available at the time that forecast was prepared. APCo's actual natural gas costs are reasonable given the strategies and practices used to procure its natural gas requirements. APCo has, and will continue to procure and manage its natural gas fuel supplies and transportation costs in a prudent manner to provide reliable supply at the lowest reasonable cost.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Appalachian Power Company
Forecast of Gas Delivered Costs
For the Period Ended August 2023

	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Forecast Period Total/ Average
MMBtu	3,122,863	2,638,605	2,943,109	3,024,072	3,384,708	2,887,392	3,143,083	2,925,041	2,035,058	2,902,819	3,352,998	2,925,255	35,285,003
$/MMBtu	$2.43	$2.41	$2.79	$3.11	$3.68	$3.55	$3.16	$2.54	$2.30	$2.36	$2.47	$2.33	$2.79

Appalachian Power Company
Gas Consumption - Projected vs Actual
For the 12 Months Ended February 28, 2022

	Review Period Consumption		
	Projected	Actual	
Total Cost	$82,812,212	$127,295,213	54%
MMBtu	34,329,388	33,725,536	-2%
$/MMBtu	2.41	3.77	56%

Appalachian Power Company
Exemption Report - Transactions of Natural Gas Fuel Assets
For the Period January 1, 2021 to February 28, 2022

Note there were NO affiliate natural gas transactions.

Note there were NO natural gas financial hedge transactions.

Non Affiliate Sale Transaction(s): [A]

Transaction Date	Gas Flow Date	Transporting Pipeline	Sold To	Volume (MMBtu)	Revenue ($) (From Sale)	Weighted Average $/MMBtu (Sale Price)	Cost ($) (From Purchase)	Weighted Average $/MMBtu (Purchase Price)	Sale of Gas Gain (Loss) [B]
4/27/2021	4/27/2021	Eastern Gas Transmission and Storage, Inc.	J. Aron & Company LLC	40,000	$88,800	$2.2200	$87,100	$2.1775	$1,700
4/28/2021	4/28/2021	Eastern Gas Transmission and Storage, Inc.	J. Aron & Company LLC	30,000	$67,500	$2.2500	$67,719	$2.2573	($219)
6/28/2021	6/28/2021	East Tennessee Natural Gas, LLC	Sequent Energy Management, L.P.	15,000	$57,000	$3.8000	$57,000	$3.8000	$0
6/30/2021	6/30/2021	East Tennessee Natural Gas, LLC	Sequent Energy Management, L.P.	15,000	$56,250	$3.7500	$60,075	$4.0050	($3,825)
9/13/2021	9/13/2021	East Tennessee Natural Gas, LLC	Sequent Energy Management, L.P.	29,000	$158,050	$5.4500	$163,850	$5.6500	($5,800)
9/13/2021	9/14/2021	East Tennessee Natural Gas, LLC	Sequent Energy Management, L.P.	25,000	$138,000	$5.5200	$138,000	$5.5200	$0
11/19/2021	11/19/2021	East Tennessee Natural Gas, LLC	Sequent Energy Management, L.P.	25,000	$130,000	$5.2000	$133,750	$5.3500	($3,750)

[A] The sales do not include pipeline cashouts, as described under the terms and conditions of the East Tennesse Natural Gas, LLC pipeline tariff.

[B] It should be noted that the gain or loss as a result from the sale has been calculated based on the weighted average of total purchases for the particular gas flow date; the accouting calculation includes the cost of inventory (if applicable).

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
DIRECT TESTIMONY
OF
JEFFREY C. DIAL

Company Exhibit
JCD-D

DIRECT TESTIMONY OF
JEFFREY C. DIAL
ON BEHALF OF APPALACHIAN POWER COMPANY AND
WHEELING POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA IN CASE NO. 22-______________

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

A. My name is Jeffrey C. Dial. I am employed by the American Electric Power Service Corporation ("AEPSC"), a subsidiary of American Electric Power Company, Inc. ("AEP"), in the regulated Commercial Operations organization as Director - Coal, Transportation and Reagent Procurement. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND.

A. I graduated from the University of Akron in 1983, with a degree in Accounting, and I am a Certified Public Accountant in the State of Ohio. I have also participated in various management training and development programs, including the AEP Management Development Executive Education program provided by The Ohio State University Fisher College of Business.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL BACKGROUND.

A. In February 1984, I was hired by AEPSC as an assistant auditor with the responsibility for conducting operational and financial audits of the various AEPSC and third party entities. In 1989, I joined the Contract Administration department as a Contract Analyst where I was primarily responsible for the negotiation and administration of our long-term coal supply agreements and fuel data reporting system for all of the AEP

East Operating Companies. I joined the Procurement department as a Coal Procurement Agent in 1995 and was responsible for the coal procurement and inventory management for various AEP subsidiaries, including Ohio Power Company ("OPCo"), Columbus Southern Power Company, Kentucky Power Company ("KPCo"), and as agent for Ohio Valley Electric Company ("OVEC") and Indiana Kentucky Electric Corporation ("IKEC"). I held various positions of increasing responsibility in the Procurement department until 2009, when I moved into the Transportation and Logistics section of Fuel Procurement as the Manager of Marketing, Transportation and Logistics and was responsible for all of the transportation and logistics functions including contract negotiations with the various transportation providers and managing the day-to-day deliveries to all of the AEP Power Plants. In May of 2018, I was promoted to my current role as Director - Coal, Transportation, and Reagents Procurement.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS DIRECTOR – COAL, TRANSPORTATION, AND REAGENTS PROCUREMENT.

A. I am responsible for the oversight of all coal and reagents procurement, contract negotiation, and inventory management for AEP operating companies, including Appalachian Power Company ("APCo"), Indiana Michigan Power Company ("I&M"), KPCo, Southwestern Electric Power Company ("SWEPCO"), Public Service Company of Oklahoma ("PSO"), Wheeling Power Company ("WPCo"), and as an agent for OVEC and IKEC. I am also responsible for the oversight of all rail, barge, truck, and transloading agreements related to coal and reagents.

Q. FOR WHOM ARE YOU PROVIDING TESTIMONY IN THIS PROCEEDING?

A. I am providing testimony on behalf of both APCo and WPCo, (together, "the Companies").

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY TO ANY REGULATORY AGENCIES?

A. Yes. I have provided testimony before the Public Service Commission of West Virginia on behalf of APCo and WPCo. I have also provided testimony before the Indiana Utility Regulatory Commission on behalf of I&M, the Michigan Public Service Commission on behalf of I&M, the Public Service Commission of Kentucky on behalf of KPCo and the Oklahoma Corporation Commission on behalf of PSO.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to:

(1) Provide an overview of the coal market in which coal was procured during the twelve month period ending February 28, 2022 ("Review Period");

(2) Discuss the inventory management measures;

(3) Describe the coal delivery forecast for the twelve month period ending August 2023 ("Forecast Period");

(4) Describe the portfolio of coal supply agreements and supplier performance for the twelve month period ending December 31, 2021;

(5) Discuss the coal purchasing strategy; and

(6) Discuss the constraints and challenges of the current coal market; and

(7) Discuss the reasonableness of the actual and projected coal costs.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibits:

- Confidential Company Exhibit JCD-D1 details by month the Companies' forecasted delivered cost of coal for the Forecast Period;
- Company Exhibit JCD-D2 summarizes the projected versus actual delivered cost of coal for the Review Period; and
- Confidential Company Exhibit JCD-D3 summarizes both APCo's and KPCo's coal contracts in effect between January 1, 2021 and December 31, 2021 and associated supplier performance (Mitchell is operated by KPCo on behalf of itself and WPCo).
- Company Exhibit JCD-D4 is the March 1, 2021 through February 28, 2022 exemption report for coal transactions; and

Q. PLEASE IDENTIFY AND DESCRIBE THE COMPANIES' COAL GENERATING PLANTS.

A. The Amos Generating Station ("Amos"), the Mountaineer Generating Station ("Mountaineer"), and the Mitchell Generating Station ("Mitchell") operated throughout the Review Period and are projected to receive coal deliveries throughout the entire Forecast Period.

Amos, a coal-fired plant owned by APCo and located in Winfield, West Virginia, consists of three coal-fired generating units with a total generating capacity of 2,930 megawatts. To comply with emission limits, Amos uses Selective Catalytic Reduction ("SCR") systems to reduce nitrogen oxide ("NO_x") emissions and Flue Gas

Desulfurization ("FGD") systems to reduce sulfur dioxide ("SO_2") emissions. The units burn a blend of high and low-sulfur bituminous coals in the steam generators.

Mountaineer, a coal-fired plant owned by APCo and located near New Haven, West Virginia, consists of one coal-fired generating unit with a total generating capacity of 1,320 megawatts. To comply with emission limits, Mountaineer uses an SCR system to reduce NO_x emissions and an FGD system to reduce SO_2 emissions. Mountaineer burns high-sulfur bituminous coal in the steam generator.

Mitchell, fifty percent of which is owned by WPCo and fifty percent by KPCo, is a coal-fired plant located near Moundsville, West Virginia. Mitchell consists of two coal-fired generating units with a total generating capacity of 1,560 megawatts. To comply with emission limits, Mitchell uses SCR systems to reduce NO_x emissions and FGD systems to reduce SO_2 emissions. The units burn a blend of high- and low-sulfur bituminous coals in the steam generators. KPCo operates Mitchell, including fuel procurement and inventory management functions.

MARKET OVERVIEW

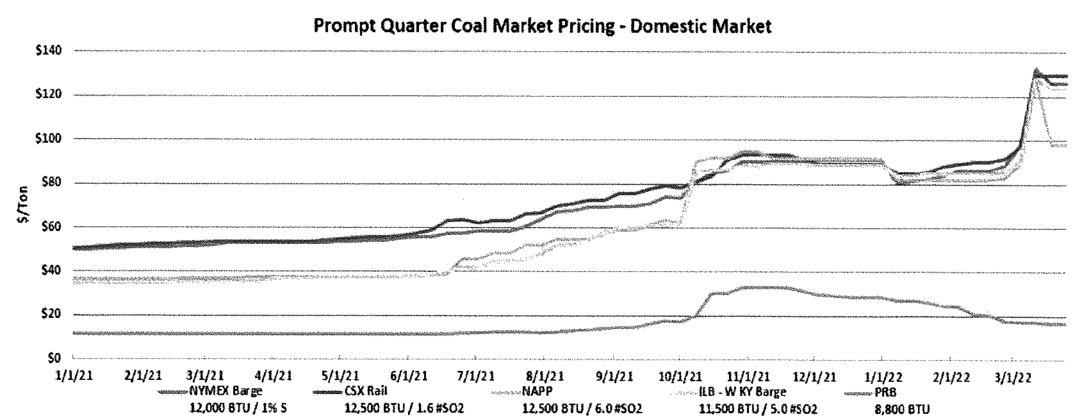
Q. PLEASE DESCRIBE CHANGES IN THE COAL MARKET DURING THE REVIEW PERIOD AND THROUGH THE FIRST QUARTER OF 2022.

A. As stated in my 2021 ENEC Reopener testimony, coal prices were generally flat during the winter of 2020 and through the first half of 2021. However, domestic and global coal prices increased rapidly in the second half of 2021 as the demand for domestic and global coal increased significantly. The increase in coal demand was primarily due to increases in natural gas prices making coal the lower cost option to generate electricity.

Company witness Stutler explains what happened in the natural gas market from the winter of 2020 through early 2022. This increase in demand for coal for power production along with stronger demand in the export market and the lingering effects of COVID-19 caused tight supply from all coal basins in 2021 and thus far in 2022, as well as sharply higher coal prices. The supply of coal is projected to be constrained throughout the remainder of 2022.

A comparison of prices for the coal markets from early 2021 through the first quarter of 2022 shows the drastic price increases in all of the basins, as can be seen in Figure 1 below. Low-sulfur Central Appalachian ("CAPP") barge coal (12,000 Btu per lb. 1.67 lbs. SO_2) began 2021 with a price of $51.30 per ton and is currently at a price of $126.00 per ton. The high-sulfur Northern Appalachian ("NAPP") coal (12,500 Btu per lb. 6 lbs. SO_2) markets also increased during the same period from approximately $36.50 per ton to approximately $95.00 per ton. Illinois Basin ("ILB") coal (11,500 Btu per lb. 5.00 lbs. SO2) also increased over the same period from $34.50 per ton to $110.50 per ton while Powder River Basin ("PRB") coal (8,800 Btu per lb. .80 lbs. SO2) also saw increases from $11.60 per ton to $16.80 per ton with a high of

Figure 1: Per Argus (12/31/2020 through 03/25/2022)

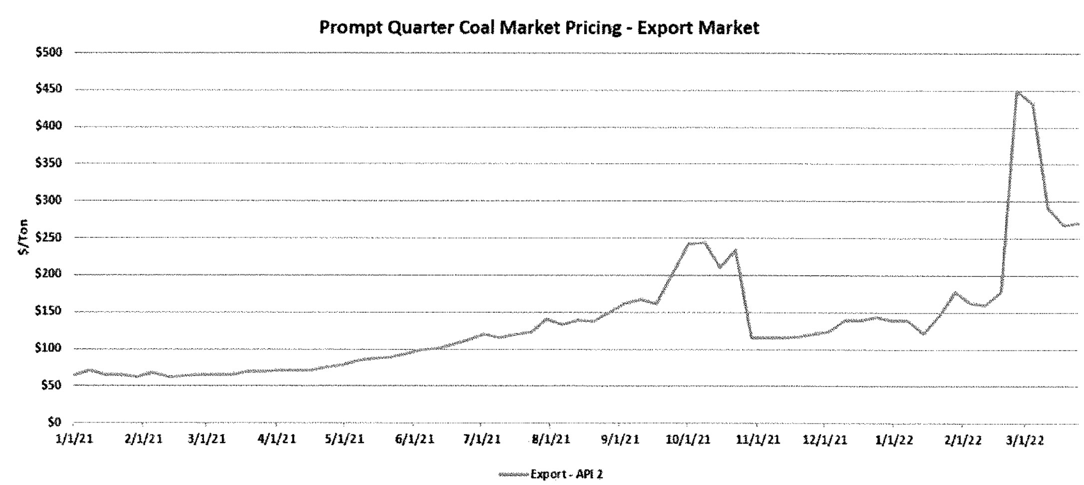


$33.00 per ton in late 2021. High demand and limited coal availability in 2022 are projected to keep coal prices at elevated levels (see Figure 1).

Q. HOW DID THE COAL EXPORT MARKET AFFECT THE COMPANIES' ABILITY TO PROCURE COAL IN 2021?

A. As discussed in my 2021 ENEC Reopener testimony, due to high natural gas prices in Europe, U.S. coal became economic for European utilities. This led to an increase in the demand for U.S. coal as coal suppliers began dedicating larger portions of their production to the export markets. In September 2021, export coal prices had increased to approximately $200 per ton from mid-year pricing of approximately $100 per ton, which amounts to a 100% increase in price in three months (see Figure 2). In recent months, export coal prices have been as high as $450 per ton, which will continue to limit the availability of domestic coal.

Figure 2: Per Argus-McCloskey (12/31/2020 through 03/25/2022)



Q. WHAT EFFECT DID MARKET CONDITIONS HAVE ON THE PRICE THE COMPANIES PAID FOR COAL DURING THE REVIEW PERIOD?

A. The market conditions did not directly affect the price paid for coal during 2021 because the contracts had been executed prior to 2021. However, market conditions will begin impacting the price for coal in 2022 as newer higher priced agreements are layered into the portfolio. The cost of coal consumed by APCo was 209.36 cents/MMBtu which was approximately 1% higher than prices paid in 2020 of 206.60 cents/MMBtu. For WPCo, the cost of coal was 207.21 cents/MMBtu which was approximately 7% lower than what was consumed in 2020 of 220.10 cents/MMBtu.

INVENTORY MANAGEMENT

Q. PLEASE DESCRIBE THE COMPANIES' COAL INVENTORY STATUS THROUGHOUT 2021.

A. As stated previously, due to the high domestic and international demand for coal, the improving economy, relatively low cost coal on the ground, and high natural gas prices, the Companies' coal-fired generation increased dramatically during the summer of 2021, which resulted in the Companies' inventories declining significantly, as can be seen in Figures 3 and 4. Inventories are expected to remain lower in 2022 due to a lack of supply.

Figure 3: APCo Inventories

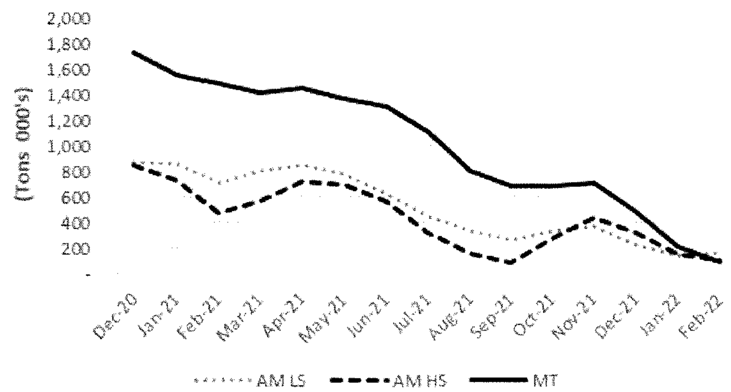
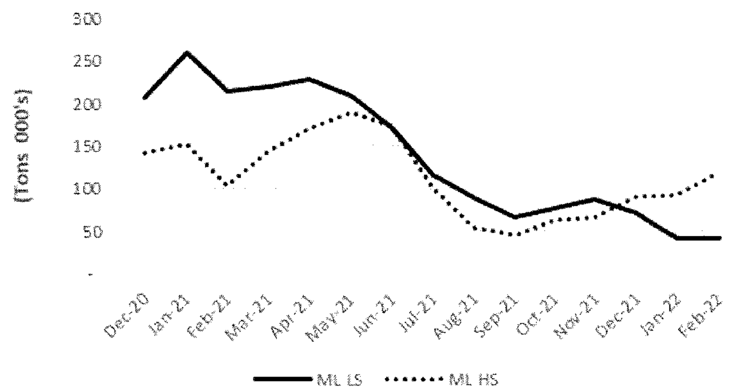


Figure 4: WPCo Inventories



Q. HAVE THE COMPANIES EVALUATED BURNING A HIGHER PERCENTAGE OF HIGH SULFUR COAL TO REDUCE THEIR RELIANCE ON LOW SULFUR COAL?

A. Yes. The Companies continue to evaluate the possibility of burning a higher percentage of high sulfur coal in their blends. A test burn of 100% high sulfur coal that does not require a low sulfur coal blend to meet the FGD specifications is currently scheduled for July 2022 at the Amos plant. Additionally, the Mitchell plant increased its blend of high sulfur coal by approximately 15% from 2020 to 2021.

COAL DELIVERY FORECAST

Q. WHEN WAS THE COMPANIES' FORECAST OF DELIVERED COAL COSTS TO THEIR POWER PLANTS FOR THE FORECAST PERIOD PREPARED?

A. Data was prepared in December 2021, by coal purchase type (Committed, Non-Committed, and Total), price per ton (FOB mine), Transportation Cost, and Total Delivered Cost, along with the total weighted average forecasted cost of coal delivered to the generating stations, on a cents per million BTU basis, for the Forecast Period. An adjustment was made to the forecast in February 2022 to reflect the expected deliveries during the Forecast Period. This information was provided for use in preparing the Companies' Expanded Net Energy Cost ("ENEC") forecast. Committed coal purchases reflect executed contracts for a specific agreed upon volumes of coal, while Non-Committed coal reflects volumes of coal that have not yet been purchased to meet the forecasted consumption. The Non-Committed coal volumes are priced based on forward market prices. Please refer to Confidential Company Exhibit JCD-D1, which details by calendar month the forecasted delivered coal cost for the Forecast Period.

Q. IN PREPARING THE FORECAST OF DELIVERED COAL COSTS, HAVE THE COMPANIES CHANGED THE METHODOLOGY THAT HAS HISTORICALLY BEEN USED IN THE DEVELOPMENT OF SUCH FORECASTS?

A. No. The methodology used in this forecast is consistent with the methodology that has been used by the Companies and presented to this Commission in previous ENEC proceedings. However, coal consumption is adjusted on a monthly basis to reflect current market conditions.

THE COMPANIES' PORTFOLIO OF COAL SUPPLY AGREEMENTS

Q. PLEASE SUMMARIZE THE COMPANIES' PORTFOLIO OF COAL SUPPLY AGREEMENTS IN EFFECT DURING THE REVIEW PERIOD AND TO BE IN EFFECT IN THE FORECAST PERIOD.

A. Information regarding the Companies' long-term and short-term agreements for 2021 and the Forecast Period is summarized in Confidential Company Exhibit JCD-D3.

Because of supply constraints and associated economics, the Companies endeavored, and were successful in their efforts, to further diversify their supplier portfolio supply. In 2021, that included adding seven new CAPP and three new NAPP suppliers. The Companies also purchased coal from three suppliers of ILB with varying terms of up to five years. Additional spot coal will be purchased when available.

Q. DID EITHER OF THE COMPANIES EXPERIENCE ANY CONTRACT DELIVERY ISSUES DURING CALENDAR YEAR 2021?

A. Yes. As indicated in my 2021 ENEC Reopener testimony, the Companies experienced supply delivery issues with several vendors, ranging from non-conforming quality specifications, producer under-performance, and mine- related issues such as roof falls, methane levels, and high employee absenteeism rates as a result of the COVID-19 pandemic. Contract shortfalls for APCo amounted to approximately 1.8 million tons of high sulfur NAPP coal and approximately 180,000 tons of low sulfur CAPP coal. The shortfalls for WPCo's share of the Mitchell Plant (i.e. 50%) amounted to approximately 220,000 tons of high sulfur NAPP coal and approximately 75,000 tons of low sulfur CAPP coal for calendar year 2021. While the Companies continuously monitored the issue, given the adequate inventory levels in the first half of 2021, it did not become a concern until the generation increased significantly in the second half of 2021.

The Companies have historically worked with their suppliers to make up shortfalls in a future period based on future open positions. It is valuable to preserve good relationships with these suppliers, who, in turn, are often willing to accommodate changing needs of the Companies when they are able to do so. For example, the same vendors who delivered shortfall tonnages in 2021, were willing in 2020 to delay into the future the shipment of 2.6 million tons when the Companies were not in a position to receive them.

With the exception of three agreements with two vendors, the Companies have agreed to all shortfall makeup in 2022 at the 2021 contract prices. The Companies are currently in discussions with the remaining two vendors on the remaining three agreements. Information regarding the Companies' contract shortfalls for 2020 and 2021 is detailed in Confidential Company Exhibit JCD-D3.

<u>COAL PURCHASING STRATEGY</u>

Q. PLEASE DESCRIBE THE COMPANIES' COAL PURCHASING STRATEGY.

A. The Companies' coal procurement strategy is not tied solely to the coal delivery forecast provided to the Production Costing group to develop the forecast filed in this case, or to that resulting forecast. As described by Company witness Sloan, the forecast was used to determine the forecasted cost of fuel consumed at the Companies' coal plants, as computed by the PLEXOS simulation model, for the Forecast Period of September 1, 2022 through August 31, 2023. The strategy for actual coal procurement is not static; rather it is based on periodic updates of the forecast and continuous market monitoring and evaluation both of which help to determine when to issue Requests for Proposals ("RFPs") or to make prompt purchases from the market if available. The purchasing needs are determined over time based on the periodic updates of the forecasts the monthly consumption forecasts I mentioned previously, and current inventory levels.

Additionally, the Companies evaluate unsolicited offers, monitor coal markets for availability and price, and consider coal supplies from non-traditional market as necessary.

Lastly, the Companies rely on the physical inventory, to compensate for periods of high consumption or to minimize supply disruptions. Supply disruptions can be caused by events such as, but not limited to, inclement weather, river levels, mine production challenges, shortage of equipment, or shortage of labor.

Q. HAVE THE COMPANIES PROCURED ANY ADDITIONAL COAL FOR 2022 AND BEYOND OR ISSUED ANY RFPs SINCE THE MARCH 23, 2022 HEARING IN CASE NO. 21-0339-E-ENEC?

A. Yes. The Companies continued to work with suppliers and were able to secure an additional 400,000 tons for 2022 and 800,000 tons for 2023. Additionally, the Companies' issued a RFP on April 6, 2022, seeking coal for the period of 2022 through 2025, but are willing to consider longer term deals if offered. The results of that RFP are not yet known.

Q. IS IT THE GOAL OF THE COMPANIES TO INCREASE THEIR SUPPLIES OF COAL?

A. Yes. The Companies understand that the Commission wishes them to operate their coal-fired plants at higher than historical capacity factors. In its Order of September 2, 2021, the Commission evidenced its expectations in this regard by using a 69% capacity factor in its projections of the Companies' ENEC costs.

Unfortunately, the shortages of supply and elevated prices that have constrained the coal market have severely limited the Companies' ability to secure enough coal to achieve high-capacity factors on a consistent basis. While the Companies have sufficient coal under contract to meet the level of generation forecasted by Company witness Sloan, under present market conditions it will be challenging, to say the least, to achieve the desired balance among maintaining coal inventories at proper levels, ensuring the ability of the Companies' coal-fired units to operate when they are most needed, and taking advantage, to the extent possible, of the opportunities for coal-fired generation presented by current market conditions. At this time, it is uncertain how long current coal procurement constraints will continue. When constraints do ease and when guided by the clarification that the Companies have sought from the Commission on the role which the Commission wishes the principle of economic dispatch to play in the Companies' operational decisions, the Companies hope to secure and burn more coal to the ultimate advantage of their customers in West Virginia.

EXEMPTION REPORTING

Q. DID THE COMPANIES HAVE ANY EXEMPT COAL TRANSACTIONS FOR THEIR PLANTS THAT OCCURRED IN THE REVIEW PERIOD?

A. No. The Companies did not have any exempt coal transactions during the Review Period in Company Exhibit JCD-D4. Additionally, there were no coal hedge or affiliate coal sale transactions executed by the Companies during the Review Period.

CONCLUSION

Q. ARE THE COMPANIES' ACTUAL AND PROJECTED COAL COSTS REASONABLE?

A. Yes. The forecasted delivered cost of coal shown on Companies Exhibit JCD-D1 is reasonable based upon the information available at the time that forecast was prepared. The Companies' actual coal costs are reasonable given the strategies used to procure their coal requirements. The Companies have procured and managed, and, subject to Commission directives, intend to continue to procure and manage, their coal supplies and transportation in a prudent manner to provide reliable supply at the lowest reasonable cost.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APPALACHIAN POWER COMPANY
Forecast of Coal Delivered Costs
For the 12 months ending August 2023

	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Forecast Period Total/ Average
Committed	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Tons (000)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8,381
$/Ton FOB Mine	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	55.53
$/Ton Transportation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	6.87
$/Ton Delivered	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62.40
Btu/Lb	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	12,412
C/MMBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	251.38
Not Committed	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Tons (000)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0
$/Ton FOB Mine	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0
$/Ton Transportation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0
$/Ton Delivered	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0
Btu/Lb	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0
C/MMBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Tons (000)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8,381
$/Ton FOB Mine	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	55.53
$/Ton Transportation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	6.87
$/Ton Delivered	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	62.40
Btu/Lb	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	12,412
C/MMBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	251.38

Contains Confidential Information

WHEELING POWER COMPANY
Forecast of Coal Delivered Costs
For the 12 months ending August 2023

	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Forecast Period Total/ Average
Committed	[redacted]												
Tons (000)													874
$/Ton FOB Mine													55.57
$/Ton Transportation													2.96
$/Ton Delivered													58.53
Btu/Lb													12,446
C/MMBtu													235.14
Not Committed													
Tons (000)													0
$/Ton FOB Mine													0
$/Ton Transportation													0
$/Ton Delivered													0
Btu/Lb													0
C/MMBtu													0
Total													
Tons (000)													874
$/Ton FOB Mine													55.57
$/Ton Transportation													2.96
$/Ton Delivered													58.53
Btu/Lb													12,446
C/MMBtu													235.14

Contains Confidential Information

*Wheeling Power Portion; 50% of the Mitchell Plant

Appalachian Power Company
Delivered Cost of Coal - Projected vs Actual
For the Twelve Months Ended February 28, 2022

	Delivered Cost	
	Projected	**Actual**
Tons (000)	7,511	4,963
$/Ton	$43.30	$51.80
Btu/Lb	12,341	12,201
¢/MMBtu	175.45	212.27

Wheeling Power Company
Delivered Cost of Coal - Projected vs Actual
For the Twelve Months Ended February 28, 2022

	Delivered Cost*	
	Projected	**Actual**
Tons (M)	839	860
$/Ton	$47.76	$48.47
Btu/Lb	12,407	12,499
¢/MMBtu	192.48	193.91

* WPCo share only

Appalachian Power Company
Portfolio of Coal Supply Agreements
As of December 31, 2021

Contains Confidential Information

LONG-TERM CONTRACTS

											Shipment Rejection Limits			
	Vendor	Contract Number	Delivery Start Date	Expiration Date	Contract Quantity (Tons)	2021 Shortfall Tonnage Yes/No	2021 Shortfall Tonnage	Plant(s)	Pricing	Transportation Method	BTU (Min)	Moisture (Max)	Ash (Max)	Lbs SO2/ MMBTU (Max)
1	ACNR Coal Sales, Inc[1]	02-10-06-901	9/1/2007	06/30/222	[redacted]			Amos Mountaineer	[redacted]					
2	ACNR Coal Sales, Inc[2]	02-10-12-900	1/1/2012	12/31/2023	[redacted]			Amos Mountaineer	[redacted]					
3	Alliance Coal, LLC	02-10-19-9M1	1/1/2020	6/30/2022	[redacted]			Amos Mountaineer	[redacted]					
4	Alliance Coal, LLC	02-10-19-9M2	1/1/2021	12/31/2022	[redacted]			Amos Mountaineer	[redacted]					
5	Alliance Coal, LLC	02-10-21-9M2	1/1/2023	12/31/2024	[redacted]			Amos Mountaineer	[redacted]					
6	Alliance Coal, LLC	02-10-21-9M5	1/1/2023	12/31/2024	[redacted]			Mountaineer	[redacted]					
7	Alpha Thermal Coal Sales Company	02-40-21-9M2	1/1/2022	12/31/2023	[redacted]			Amos	[redacted]					
8	Alpha Thermal Coal Sales Company	02-40-21-9M3	1/1/2023	12/31/2024	[redacted]			Amos	[redacted]					
9	Alpha Thermal Coal Sales Company[3]	02-40-18-009	1/1/2019	12/31/2021	[redacted]			Amos	[redacted]					
10	Alpha Thermal Coal Sales Company[3]	02-40-19-9M2	1/1/2020	4/30/2022	[redacted]			Amos	[redacted]					
11	Alpha Thermal Coal Sales Company[3]	02-40-19-9M5	1/1/2021	12/31/2022	[redacted]			Amos	[redacted]					
12	Blackhawk Coal Sales, LLC	02-40-18-022	1/1/2020	12/31/2021	[redacted]			Amos	[redacted]					
13	Blackhawk Coal Sales, LLC	02-40-21-9M1	1/1/2022	12/31/2023	[redacted]			Amos	[redacted]					
14	Blackhawk Coal Sales, LLC	02-40-21-9M4	1/1/2022	12/31/2026	[redacted]			Amos	[redacted]					
15	Case Caol Sales, LLC	02-40-21-004	2/1/2022	1/31/2024	[redacted]			Amos	[redacted]					
16	Consol Pennsylvania Coal Company LLC	02-10-21-001	1/20/2022	12/31/2024	[redacted]			Amos Mountaineer	[redacted]					
17	Iron Coal Sales, LLC	02-10-21-9M3	1/1/2022	12/31/2024	[redacted]			Amos Mountaineer	[redacted]					
18	Lexington Coal Company, LLC	02-40-21-003	1/1/2022	12/31/2024	[redacted]			Amos	[redacted]					
19	River Trading Company	02-40-21-002	1/1/2022	12/31/2023	[redacted]			Amos	[redacted]					
20	Rosebud Mining Company	02-10-21-9M6	1/1/2022	12/31/2024	[redacted]			Mountaineer	[redacted]					

1: Previously American Coal Sales, Inc.

2: Previously Consolidation Coal Company & McElroy Coal Company

3: Previously Contura Coal Sales, LLC

Appalachian Power Company
Portfolio of Coal Supply Agreements
As of December 31, 2021

SHORT-TERM CONTRACTS

											Shipment Rejection Limits			
	Vendor	Contract Number	Delivery Start Date	Expiration Date	Contractual Quantity (Tons)	2021 Shortfall Tonnage Yes/No	2021 Shortfall Tonnage	Plant(s)	Pricing	Transportation Method	BTU (Min)	Moisture (Max)	Ash (Max)	Lbs SO2/ MMBTU (Max)
1	Hawkeye Contracting Company	02-40-21-001	11/1/2021	3/31/2022	[redacted]			Amos	[redacted]					
2	Javelin Global Commodities	02-40-19-003	1/1/2021	12/31/2021	[redacted]			Amos	[redacted]					
3	Javelin Global Commodities (UK) Ltd	02-40-19-004	1/1/2022	12/31/2022	[redacted]			Amos	[redacted]					

Wheeling Power Company
Portfolio of Coal Supply Agreements
As of December 31, 2021

LONG-TERM CONTRACTS

	Vendor	Contract Number	Delivery Start Date	Expiration Date	Contractual Quantity (Tons)*	2021 Shortfall Tonnage Yes/No	2021 Shortfall Tonnage*	Plant(s)	Pricing	Transportation Method	Shipment Rejection Limits BTU (Min)	Moisture (Max)	Ash (Max)	Lbs SO2/ MMBTU (Max)
1	ACNR Coal Sales, Inc[1]	07-77-05-900ACNR-C	1/1/2014	12/31/2023	[redacted]	[redacted]	[redacted]	Mitchell	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	Alpha Thermal Coal Sales Company[2]	03-00-18-004	1/1/2019	12/31/2021	[redacted]	[redacted]	[redacted]	Mitchell	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	Alpha Thermal Coal Sales Company	03-00-19-9M1	1/1/2021	4/30/2022	[redacted]	[redacted]	[redacted]	Mitchell	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	Alpha Thermal Coal Sales Company	03-00-21-9M2	1/1/2022	12/31/2023	[redacted]	[redacted]	[redacted]	Mitchell	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	Alpha Thermal Coal Sales Company	03-00-21-9M3	1/1/2023	12/31/2024	[redacted]	[redacted]	[redacted]	Mitchell	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	BAMM, Inc.	03-00-21-003	1/1/2022	12/31/2023	[redacted]	[redacted]	[redacted]	Mitchell	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	Blackhawk Coal Sales, LLC	03-00-18-010	1/1/2019	12/31/2021	[redacted]	[redacted]	[redacted]	Mitchell	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	Blackhawk Coal Sales, LLC	03-00-21-9M1	1/1/2022	12/31/2023	[redacted]	[redacted]	[redacted]	Mitchell	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	Blackhawk Coal Sales, LLC	03-00-21-9M4	1/1/2023	12/31/2026	[redacted]	[redacted]	[redacted]	Mitchell	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	Javelin Global Commodities	03-00-19-002	1/1/2021	10/31/2022	[redacted]	[redacted]	[redacted]	Mitchell	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1: Previously Consolidation Coal Company and McElroy Coal Company

2: Previously Contura Cole Sales, LLC

Wheeling Power Company

Portfolio of Coal Supply Agreements
As of December 31, 2021

SHORT-TERM CONTRACTS

	Vendor	Contract Number	Delivery Start Date	Expiration Date	Contractual Quantity (Tons)*	2021 Shortfall Tonnage Yes/No	2021 Shortfall Tonnage*	Plant(s)	Pricing	Transportation Method	Shipment Rejection Limits BTU (Min)	Moisture (Max)	Ash (Max)	Lbs SO2/ MMBTU (Max)
1	Alpha Thermal Coal Sales Company[1]	03-00-19-9M3	1/1/2022	12/31/2022	[redacted]	[redacted]	[redacted]	Mitchell	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	River Trading Company	03-00-21-004	4/1/2022	12/31/2022	[redacted]	[redacted]	[redacted]	Mitchell	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1: Previously Contura Coal Sales, LLC

Appalachian Power Company
Exemption Report - Transactions of Coal Fuel Assets
For the Period March 1, 2021 to February 28, 2022

Note there were NO coal hedge transactions.

There were NO Non-Affiliate Coal Sale Transactions

Wheeling Power Company
Exemption Report - Transactions of Coal Fuel Assets
For the Period March 1, 2021 to February 28, 2022

Note there were NO coal hedge transactions.

There were NO Non-Affiliate Coal Sale Transactions

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
DIRECT TESTIMONY
OF
SHELLI A. SLOAN

COMPANY EXHIBIT SAS-D

DIRECT TESTIMONY OF
SHELLI A. SLOAN
ON BEHALF OF APPALACHIAN POWER COMPANY AND
WHEELING POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA IN CASE NO. 22-______________

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

A. My name is Shelli A. Sloan. I am employed by the American Electric Power Service Corporation ("AEPSC"), a subsidiary of American Electric Power Company, Inc. ("AEP"), in the Corporate, Planning and Budgeting ("CP&B") organization as Director Financial Support and Special Projects. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I earned a Bachelor of Science in Business Administration Degree from the Ohio State University in 1991 and a Master of Business Administration from Ashland University in 2002. I was hired by AEPSC in 1998 into the Information Technology organization where I performed multiple roles in the Resource Management group and the Project Management Office. In 2009 I joined Regulatory Services as a Regulatory Consultant supporting fuel filings for all AEP operating companies.

From 2012 through 2017, I was a Regulatory Case Manager, overseeing large and complex regulatory filings for multiple AEP operating companies. In 2018, I was promoted to the position of Director Case Support and Special Projects where I led a team responsible for Integrated Resource Plan filings, Renewable acquisition filings, and witness support in all AEP jurisdictions. I moved into my current role in 2021.

Q. PLEASE DESCRIBE YOUR JOB DUTIES AND RESPONSIBILITIES AS DIRECTOR FINANCIAL SUPPORT AND SPECIAL PROJECTS.

A. As Director of Financial Support and Special projects, I am responsible for directing all regulatory activities within the forecasting group, managing the overall flow of the financial forecast process, and leading various special projects involving the Finance organization. I assist in the preparation of financial forecasts in conjunction with operating company personnel, variance analyses, regulatory filings, and other ad hoc analysis for the AEP System's utility companies. In this role, I assist in the preparation and review of short- and long-term forecasts for Appalachian Power Company ("APCo") and Wheeling Power Company ("WPCo").

Q. FOR WHOM ARE YOU PROVIDING TESTIMONY?

A. I am testifying on behalf of both APCo and WPCo (together, the "Companies").

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN ANY REGULATORY PROCEEDINGS?

A. Yes, I have testified and/or submitted testimony before the Public Service Commission of West Virginia ("Commission") in Case No. 21-0339-E-ENEC on behalf of APCo and WPCo, before the Virginia State Corporation Commission on behalf of APCo in fuel factor proceedings, before the Indiana Utility Regulatory Commission on behalf of Indiana Michigan Power Company ("I&M") in base rate case, fuel cost and rider proceedings, and before the Michigan Public Service Commission on behalf of I&M in power supply cost recovery proceedings.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to:

(1) Provide the forecast of the Companies' Expanded Net Energy Cost ("ENEC") for the twelve-month period ending August 31, 2023 ("Forecast Period");

(2) Provide the forecast of the Companies' Expanded Net Energy Requirement ("Requirement") for the Forecast Period;

(3) Provide the summary of the sources and uses of energy for the Forecast Period; and

(4) Provide unit specific data for the Forecast Period.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring the following exhibits:

- Company Exhibit SAS-D1 summarizes the Companies' forecasted ENEC and Net Energy Requirement for the Forecast Period.
- Company Exhibit SAS-D2 summarizes the Companies' Sources and Uses of Energy for the Forecast Period.
- Company Exhibit SAS-D3 details the projected West Virginia jurisdictional sales for the Forecast Period.
- Confidential Company Exhibit SAS-D4 details unit specific generation and costs information for the Forecast period.
- Company Exhibit SAS-D5 provides a high level overview of the major inputs to the ENEC forecasting methodology.

Company Exhibits SAS-D1, D2, and D3 show data for the Forecast Period and actual values per the Companies' books and records for the twelve months ended February

28, 2022 ("Historical Period"). The purpose of this presentation is to demonstrate the variances between the Forecast Period and the Historical Period.

Q. WAS THE METHODOLOGY USED TO DEVELOP THE PROJECTED ENEC FOR THIS PROCEEDING CONSISTENT WITH THE METHODOLOGY USED IN THE MOST RECENT ENEC PROCEEDING BEFORE THIS COMMISSION?

A. Yes.

Q. WHEN WAS THE FORECAST BEING USED IN THIS PROCEEDING DEVELOPED?

A. The ENEC forecast is developed over several months utilizing the methodology as described in Company Exhibit SAS-D5. Once final, the forecast is published. The forecast represents the data available during the development period and does not necessarily reflect current domestic and global market conditions, which are addressed by other Company witnesses in this proceeding. Because the different components of the ENEC forecast are inter-related, and because of the length of time it takes to develop the various inputs into and the forecast itself, it was not feasible to prepare a forecast that reflects more current conditions. Moreover, it is not known at this time whether current conditions represent a short-term anomaly or a longer-term trend. While the Companies made the top-side adjustment to the cost of coal described below, as one considers the comparisons and projections described throughout my testimony, it is important to remember that they reflect assumptions that do not take into account more recent market conditions, or current prices for coal, natural gas and energy.

The Forecast[1] was published in December 2021. In February 2022 a topside adjustment was made to the cost of coal to reflect a change made to the expected deliveries during the Forecast Period. Company witness Dial addresses the expected coal deliveries in the Forecast Period.

Q. PLEASE DESCRIBE HOW THE COMPANIES' DATA IS PRESENTED IN YOUR EXHIBITS.

A. The amounts I present for APCo are on a total-company basis. Company witness Greenhowe presents APCo data on a West Virginia jurisdictional basis. Also, according to the Commission's December 18, 2019 Order in Case No. 19-0564-E-T, WPCo's Historical Period and Forecast Period costs, capacity and energy requirements are reflected at 100% of WPCo's undivided 50% ownership interest in the Mitchell plant.

Q. PLEASE DESCRIBE THE COMPONENTS OF ENEC PROJECTED IN THIS PROCEEDING.

A. Company Exhibit SAS-D1 shows the net cost of all sources of energy incurred in supplying the Companies' internal load along with other costs and credits used in the projection of the ENEC in this proceeding. Company Exhibit SAS-D1, page 1 of 2, provides the ENEC and Company Exhibit SAS-D1, page 2 of 2, provides the

[1] The Forecast used in this ENEC is the same as presented as the Reforecast in the Reopening of Case No. 21-0339-E-ENEC

corresponding net energy requirement for each company. The costs include fossil fuel consumed, purchased power from external sources, and the financial settlement of transmission losses, all of which are partially offset by the Companies' off-system sales ("OSS") revenues. The ENEC forecast also includes certain transmission revenues, emission allowance gains, and certain other production costs. These other production costs are primarily for fuel handling and environmental compliance, including consumable chemical expenses and the cost of emission allowances. Next, I will discuss each component in more detail.

Fuel Expense and Fuel Handling (Company Exhibit SAS-D1, Page 1, lines 3 through 5)

Q. PLEASE DESCRIBE HOW THE PROJECTION FOR THE COST OF FUEL CONSUMED AND THE COST OF FUEL HANDLING WERE CALCULATED.

A. The cost of fossil fuel consumed was based on the generation forecast for each of the Companies' fossil-fueled generating units for the Forecast Period utilizing the simulation model *PLEXOS*®. *PLEXOS*® utilizes the cost of fuel delivered, provided by Company witnesses Dial and Stutler, as well as other data (fuel handling, variable operations & maintenance, consumable costs, scheduled maintenance outages, and forced outage factors) to determine the projected generation for each of the Companies' units in the PJM Interconnection, LLC ("PJM") Regional Transmission Organization power market.

The cost of fuel consumed for the Companies' coal-fired generating units is equal to the number of tons of coal consumed times the average unit cost of coal in inventory. The average cost of coal is defined as the weighted average cost of coal in inventory at the beginning of the month plus the projected cost of fuel delivered during the month. This calculation is performed for both the cost of coal (account 151 basis) and the cost of fuel handling (account 152 basis). The cost of fuel consumed for each of APCo's natural gas-fired generating units is equal to the projected cost of gas multiplied by the projected quantity of gas consumed.

Q. PLEASE COMPARE THE LEVEL OF FUEL AND FUEL HANDLING EXPENSES FOR THE HISTORICAL PERIOD TO THE PROJECTION FOR THE FORECAST PERIOD.

A. APCo's fuel and fuel handling expenses are projected to be $601.3 million for the Forecast Period, which is approximately $50.2 million higher than the costs incurred in the Historical Period. While fossil generation in the Forecast Period is projected to decrease slightly from the Historical Period, these costs are projected to increase mainly due to higher average cost of coal and gas consumed, which is projected to increase from $24.46/MWh in the Historical Period to $26.96/MWh in the Forecast Period.

WPCo's fuel and fuel handling expenses are projected to be $45.8 million for the Forecast Period, which is approximately $13.4 million lower than the costs incurred in the Historical Period. These costs are projected to decrease due to lower generation of 819 GWh during the Forecast Period, which reflects 100% of WPCo's undivided 50% ownership interest in the Mitchell plant. The average cost of coal consumed was $24.23/MWh in the Historical Period and increases to $28.22/MWh in the Forecast Period. Company witness Dial addressed the cost of coal in his testimony.

<u>Purchased Power (Company Exhibit SAS-D1, page 1, lines 7 through 14)</u>

Q. DEFINE THE COSTS THAT ARE REFLECTED UNDER THE HEADING OF PURCHASED POWER.

A. As described by Company witness Stegall, APCo's purchased power forecast includes costs associated with planned purchases under long term agreements and market purchases. In this forecast, the planned purchases are for energy from Ohio Valley Electric Corporation ("OVEC"), Summersville Hydroelectric, and solar and wind resources. OVEC and market purchases are assigned, based on cost, to either internal load or off-system sales.

WPCo's purchased power forecast includes only costs associated with market purchases made when the projected generation is not sufficient to meet projected load.

Q. PLEASE COMPARE THE LEVEL OF PURCHASED POWER COSTS FOR THE HISTORICAL PERIOD TO THE PROJECTION FOR THE FORECAST PERIOD.

A. APCo's and WPCo's combined purchased power costs are projected to be $488.8 million which is approximately $163.5 million lower than the costs incurred in the Historical Period. The decrease is mainly due to both a decrease in market energy purchases by APCo and the average cost of market energy purchases for both APCo and WPCo during the Forecast Period. Please see Company Exhibit SAS-D1 for a breakout of the purchases power expense.

PJM Ancillaries (Company Exhibit SAS-D1, page 1, lines 15 through 16)

Q. DEFINE THE COSTS THAT ARE REFLECTED UNDER THE HEADING OF PJM ANCILLARIES.

A. The costs that are reflected under the heading of PJM Ancillaries include charges and credits, where applicable, for ancillary services such as operating reserves, reactive services, black start, spinning reserves, and regulation service.

Financial Transmission Rights ("FTR") Revenue Net of Congestion Costs – Load Serving Entity ("LSE") (Company Exhibit SAS-D1, page 1, line 17)

Q. PLEASE EXPLAIN FTR REVENUE NET OF CONGESTION COSTS – LSE.

A. Within the PJM RTO, members receive FTR revenues and incur congestion costs which may or may not offset each other. FTRs are financial instruments that entitle the holder to receive compensation for certain congestion-related costs that arise when the transmission grid is heavily used. Simply put, FTRs are a partial hedge against transmission congestion costs. Congestion costs are measured as the difference in the price of megawatts for the generators in PJM vs. the LSEs.

Transmission Losses (Company Exhibit SAS-D1, page 1, line 18)

Q. DESCRIBE THE COSTS INCLUDED IN PJM TRANSMISSION LOSSES.

A. PJM transmission losses include costs and credits associated with the financial settlement of physical losses (power losses due to resistance) on the transmission system within PJM.

Consumables and Allowance Expenses (Company Exhibit SAS-D1, page 1, line 19)

Q. DESCRIBE THE COSTS INCLUDED IN CONSUMABLES AND ALLOWANCE EXPENSES.

A. Consumables and allowance expenses include the costs of consumable chemicals used in the operation of emission control facilities, a minor amount of labor at each plant to handle the chemicals, and the cost of emission allowances consumed. The consumable chemicals used in controlling air emissions include urea, limestone, and trona, while other chemicals, including lime hydrate and polymer, are primarily used for water treatment.

The consumables and allowance expense forecast is based on projected emissions for APCo's and WPCo's generating units provided by *PLEXOS*®. The allowances are priced based upon the average cost of the allowance inventory.

Q. PLEASE COMPARE THE LEVEL OF CONSUMABLES AND ALLOWANCE EXPENSES FOR THE HISTORICAL PERIOD TO THE PROJECTION FOR THE FORECAST PERIOD.

A. APCo's consumable and allowance expenses are projected to be $38.8 million, which represents a minimal increase of $1.4 million as compared to the cost incurred in the Historical Period.

WPCo's consumable and allowance expenses are projected to be $4.03 million for the Forecast Period, which is approximately $950,000 lower than the costs incurred in the Historical Period. These costs reflect 100% of WPCo's undivided 50% ownership interest in the Mitchell plant during the Forecast Period.

<u>Transmission Expense and Transmission Revenue (Company Exhibit SAS-D1, page 1, lines 21 through 24)</u>

Q. EXPLAIN HOW TRANSMISSION EXPENSE AND TRANSMISSION REVENUE IS FORECASTED.

A. These categories include both affiliated transmission revenues and affiliated expenses. All six AEP East operating companies participate directly in the settlement process. Transmission revenues are mainly a function of each operating company's projected transmission plant in service. Each company's expenses are essentially a share of the sum of all the companies' revenue requirements, allocated on a twelve-month average coincident peak load basis.

There are non-affiliated transmission revenues which are billed to other transmission owners for APCo's and WPCo's share of the revenue requirements, again based mainly on projections of transmission plant in service. Just like affiliated transmission revenues, these revenues are fully credited to West Virginia customers through the ENEC.

The Companies' ENEC also includes PJM transmission enhancement expenses for costs related to the construction of PJM-approved Regional Transmission Expansion Planning ("RTEP") projects by third-party and affiliated transmission owners.

Q. PLEASE COMPARE THE LEVEL OF TRANSMISSION EXPENSE AND TRANSMISSION REVENUE FOR THE HISTORICAL PERIOD TO THE PROJECTION FOR THE FORECAST PERIOD.

A. APCo's and WPCo's combined transmission expense and revenues are projected to be a net expense of $264.2 million, which is approximately $70.5 million higher than the net expense incurred by the Companies in the Historical Period. The increase is mainly due to higher Network Integration Transmission Services expense arising from the projected increase in AEP's total transmission investment which will be reflected in OATT rates.

<u>Off-System Sales Revenue COGS and Off-System Sales Margin (Company Exhibit SAS-D1, page 1, lines 25 through 28)</u>

Q. DESCRIBE HOW FORECASTED REVENUES FROM OSS WERE DETERMINED.

A. During the Forecast Period, OSS volume is a function of the Companies' forecasted generation and committed purchases (i.e., OVEC, solar and wind) from *PLEXOS*® and forecasted internal load on an hour-by-hour basis. An off-system sale is forecasted to occur in an hour when a company's total forecasted generation and committed purchases is greater than its internal load requirement.

Off-system sales transactions are assumed to be made with parties in the PJM market and are priced according to a forecast of market prices. The total forecast of OSS revenues is the sum of cost recovery revenue or Revenue COGS and the projection of net realization or OSS Margin. Company witness Stegall further address OSS.

Q. PLEASE COMPARE THE LEVEL OF OSS MARGIN FOR THE HISTORICAL PERIOD TO THE PROJECTION FOR THE FORECAST PERIOD.

A. APCo's and WPCo's combined OSS Margin is projected to be $33.2 million which is approximately $7.0 million higher than the margin realized by the Companies in the Historical Period. This slight increase is due to higher market prices per MWh on physical sales.

<u>Gain/(Loss) on Sale of Allowances (Company Exhibit SAS-D1, page 1, line 29)</u>

Q. PLEASE DESCRIBE HOW ALLOWANCE GAINS ARE FORECASTED.

A. APCo and WPCo carry inventories of Cross State Air Pollution Rule SO_2 allowances, Annual NOx, Seasonal NOx and Title IV SO_2 allowances. Gains are derived from the sale of allowances not needed for compliance and are calculated using the anticipated quantity of allowances to be sold and the current view of allowance market prices.

Q. WHAT CREDITS ARE SHOWN ON COMPANY EXHIBIT SAS-D1, PAGE 1, LINE 36, TITLED "SALE OF RENEWABLE ENERGY CREDITS – WV DIRECT ASSIGNED"?

A. Renewable energy credits ("RECs") are property rights to the environmental qualities of renewable electric generation, which can be sold separately from the generation itself. APCo owns RECs as a result of its wind energy purchased power contracts. The amounts shown on Company Exhibit SAS-D1, Page 1, Line 36, represent gains on the sale of RECs that are entirely attributable to APCo's WV operations. It is appropriate to show these gains separately from APCo's projected ENEC costs summarized on Exhibit SAS-D1, page 1, line 34, since APCo's ENEC costs are calculated on a total company basis. Combining the gains with other ENEC costs would understate the benefit to West Virginia customers. Company witness Greenhowe calculates the total jurisdictional ENEC cost net of these credits.

Conclusion

Q. ARE THE COMPANIES' ENEC PROJECTIONS REASONABLE?

A. Yes. The Companies' ENEC projections for the Forecast Period are reasonable based on the inputs to the forecast that were available during the development period. As I indicated at the outset of my testimony, the projections and comparisons described above do not take into account current coal, natural gas and energy prices, or recent market conditions.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APPALACHIAN POWER COMPANY
AND WHEELING POWER COMPANY
Expanded Net Energy Cost
Twelve Months Ending August 31, 2023
($000)

Line No.		APCo Actual 12-Months Ended 2/28/2022	WPCo Actual 12-Months Ended 2/28/2022	APCo Projected 12-Months Ending 8/31/2023	WPCo Projected 12-Months Ending 8/31/2023
1	Expanded Net Energy Cost ($000)				
2	Fossil Generation				
3	Fuel Expense (Energy)	504,509	54,629	549,091	42,735
4	Fuel Handling (Energy)	37,884	4,576	37,858	3,088
5	Fuel Handling (Demand)	8,702	-	14,305	-
6	Plus:				
7	Purchased Power OVEC (Energy)	43,360	-	38,286	-
8	Purchased Power PPA (Energy)	5,189	-	6,713	-
9	Purchased Power Market Purchases (Energy)	361,915	95,772	204,044	91,043
10	Purchased Power OVEC (Demand)	60,980	-	64,982	-
11	Purchased Power Affil (Demand)	-	-	-	-
12	Purchased Power - Wind (Energy)	86,946	-	82,382	-
13	Purchased Power - Wind (Demand)	1,604	-	-	-
14	Purchased Power - Solar (Energy)	-	-	1,303	-
15	PJM Ancillaries (Demand)	643	1,123	1,127	649
16	PJM Ancillaries (Energy)	7,689	1,603	8,412	1,323
17	FTR Revenue Net of Congestion Costs - LSE (Demand)	862	1,656	(8,869)	(2,280)
18	Transmission Losses (Energy)	17,956	478	10,836	614
19	Consumables and Allowance Expenses (Energy)	37,416	4,974	38,769	4,028
20	Less:				
21	Transmission Expense (Demand)	(556,323)	(69,369)	(654,698)	(70,143)
22	Transmission Expense (Energy)	106	-	106	-
23	Transmission Revenue (Demand)	419,338	12,543	458,393	2,172
24	Transmission Revenue (Energy)	-	-	-	-
25	Off-System Sales Revenue COGS (Demand)	-	-	-	-
26	Off-System Sales Revenue COGS (Energy)	66,627	3,796	77,299	3,750
27	Off-System Sales Margin (Demand)	6,141	3,044	3,592	964
28	Off-System Sales Margin (Energy)	15,077	1,997	26,765	1,890
29	Gain/(Loss) on Sale of Allowances (Energy)	0	244	1,501	568
30	Total Expanded Net Energy Cost ($000)	1,224,688	212,555	1,136,281	202,001
31	Expanded Net Energy Cost (Demand & Energy)				
32	Total Demand	203,634	56,561	264,258	65,377
33	Total Energy	1,021,054	155,994	872,023	136,624
34	Total Expanded Net Energy Cost ($000)	1,224,688	212,555	1,136,281	202,001
35	Memo Items:				
36	Sale of Renewable Energy Credits WV Direct Assigned	(7,918)	-	(13,873)	-
37	Other Pwr Revenue+Green Power + W. Va. Direct	-	-	-	-

APPALACHIAN POWER COMPANY
AND WHEELING POWER COMPANY
Expanded Net Energy Requirement
Twelve Months Ending August 31, 2023
(GWh)

Line No.		Actual 12-Months Ended 2/28/2022	Projected 12-Months Ending 8/31/2023
	Appalachian Power Company		
1	Expanded Net Energy Requirement (GWh)		
2	Fossil Generation	22,529	22,303
3	Hydro Generation	627	636
4	Solar Generation	-	67
5	Total Generation	23,156	23,007
6	Plus:		
7	Purchased Power OVEC	1,574	1,571
8	Purchased Power PPA	147	219
9	Purchased Power Market Purchases	8,536	7,600
10	Purchased Power - Wind	1,265	1,327
11	Purchased Power - Solar	-	36
12	Other*	-	(1)
13	Less:		
14	Off-System Sales	3,689	2,819
15	Expanded Net Energy Requirement (GWh)	30,989	30,940
	Wheeling Power Company		
16	Expanded Net Energy Requirement (GWh)		
17	Fossil Generation	2,443	1,624
18	Plus:		
19	Purchased Power Market Purchases	2,588	3,127
20	Less:		
21	Off-System Sales	387	125
22	Expanded Net Energy Requirement (GWh)	4,644	4,625

Notes: * Rounding or out of period adjustments.

APPALACHIAN POWER COMPANY
Sources and Uses of Energy
Twelve Months Ending August 31, 2023
(GWh)

Line No.	Sources of Energy	Actual 12-Months Ended 2/28/2022	Projected 12-Months Ending 8/31/2023
1	Steam Generation by Plant:		
2	Amos	11,182	10,393
3	Ceredo	327	120
4	Clinch River	135	66
5	Dresden	4,102	4,773
6	Mountaineer	6,783	6,952
7	Other	-	-
8	Total Steam Generation	22,529	22,303
9	Hydro Generation by Type:		
10	Conventional Hydro	687	761
11	Pumped Storage	(60)	(125)
12	Total Hydro Generation	627	636
13	Solar Generation	-	67
14	Total Generation	23,156	23,007
15	Purchased Power:		
16	Purchased Power	10,257	9,391
	Purchased Power OVEC	1,574	1,571
	Purchased Power PPA	147	219
	Purchased Power Market Purchases	8,536	7,600
	Beech Ridge	258	247
	Bluff Point	396	381
	Camp Grove	217	207
	Fowler Ridge	176	238
	Grand Ridge	218	254
17	Purchased Power - Wind	1,265	1,327
18	Purchased Power - Solar	-	36
19	Other *	-	(1)
20	Total Purchased Power	11,522.00	10,752.46
21	Total Sources of Energy	34,678	33,759
	Uses of Energy		
22	Sales to Ultimate Customers:		
23	Residential	11,136	10,944
24	Commercial	5,982	5,898
25	Industrial	8,968	8,913
26	All Other Ultimates	818	859
27	Total Sales to Ultimates	26,904	26,613
28	Associated Companies	1,709	1,700
29	Municipals and Cooperatives	1,127	1,106
30	Losses	1,249	1,522
31	Total Internal	30,989	30,942
32	Off-System Sales	3,689	2,819
33	Total Uses of Energy	34,678	33,760

Notes: * Rounding or out of period adjustments.

WHEELING POWER COMPANY
Sources and Uses of Energy
Twelve Months Ending August 31, 2023
(GWh)

Line No.	Sources of Energy	Actual 12-Months Ended 2/28/2022	Projected 12-Months Ending 8/31/2023
1	Steam Generation by Plant:		
2	Mitchell	2,443	1,624
3	Total Generation	2,443	1,624
4	Purchased Power:		
5	Purchased Power Market Purchases	2,588	3,131
6	Other *		(4)
7	Total Purchased Power	2,588	3,127
8	Total Sources of Energy	5,031	4,751
	Uses of Energy		
9	Sales to Ultimate Customers:		
10	Residential	397	395
11	Commercial	385	385
12	Industrial	3,853	3,798
13	All Other Ultimates	6	6
14	Total Sales to Ultimates	4,641	4,584
15	Losses	5	41
16	Total Internal	4,646	4,625
17	Off-System Sales	387	125
18	Total Uses of Energy	5,033	4,751

Notes: * Rounding or out of period adjustments.

APPALACHIAN POWER COMPANY
AND WHEELING POWER COMPANY
Total Ultimate Sales - State of West Virginia
Twelve Months Ending August 31, 2023
(GWh)

Line No.		Actual 12-Months Ended 2/28/2022	Projected 12-Months Ending 8/31/2023
1	Sales to Ultimate Customers		
2	Residential	4,920	4,746
3	Commercial	3,092	3,071
4	Industrial	3,924	4,045
5	Other Ultimates	29	29
6	Total Ultimate Sales	11,965	11,891
7	Wheeling Residential	397	395
8	Wheeling Commercial	388	385
9	Wheeling Industrial	3,852	3,798
10	Wheeling Other Ultimates	6	6
11	Total Wheeling Ultimate Sales	4,642	4,584

MWh

		Steam Generation (MWh)												
Unit Name	State	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Total
Amos 1	WV	[redacted]												
Amos 2	WV													
Amos 3	WV													
Ceredo 1	WV													
Ceredo 2	WV													
Ceredo 3	WV													
Ceredo 4	WV													
Ceredo 5	WV													
Ceredo 6	WV													
Clinch R 1	VA													
Clinch R 2	VA													
Dresden	OH													
Mountaineer	VA													

($000)

Unit Name	State	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Total
Amos 1	WV	[redacted]												
Amos 2	WV													
Amos 3	WV													
Ceredo 1	WV													
Ceredo 2	WV													
Ceredo 3	WV													
Ceredo 4	WV													
Ceredo 5	WV													
Ceredo 6	WV													
Clinch R 1	VA													
Clinch R 2	VA													
Dresden	OH													
Mountaineer	WV													

Fuel Handling Energy

Company Confidential Exhibit SAS-D4

Public Version

($000)

Fuel Handling Cost

Unit Name	State	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Total
Amos 1	WV	[redacted]												
Amos 2	WV													
Amos 3	WV													
Mountaineer	WV													

Unit Name	State													
Amos 1	WV													
Amos 2	WV													
Amos 3	WV													
Mountaineer	WV													

Unit Name	State													
Ceredo 1	WV													
Ceredo 2	WV													
Ceredo 3	WV													
Ceredo 4	WV													
Ceredo 5	WV													
Ceredo 6	WV													

($000) Gas Transp Res Fees -Steam 5010034

Unit Name	State	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Total
Clinch R 1	VA	[redacted]												
Clinch R 2	VA													

Unit Name	State													
Dresden	OH	[redacted]												

($000)

Unit Name	State	Description	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Total
Amos 1	WV	Urea Expense	[redacted]												
Amos 2	WV	Urea Expense													
Amos 3	WV	Urea Expense													
Ceredo 1	WV	Urea Expense													
Ceredo 2	WV	Urea Expense													
Ceredo 3	WV	Urea Expense													
Mountaineer	WV	Urea Expense													
Mountaineer	WV	Urea Handling													
Amos 1	WV	Trona Expense													
Amos 2	WV	Trona Expense													
Amos 3	WV	Trona Expense													
Mountaineer	WV	Trona Expense													
Mountaineer	WV	Trona Handling													
Amos 1	WV	Limestone Expense													
Amos 2	WV	Limestone Expense													
Amos 3	WV	Limestone Expense													
Mountaineer	WV	Limestone Expense													
Amos 1	WV	Limestone Handling													
Amos 2	WV	Limestone Handling													
Amos 3	WV	Limestone Handling													
Mountaineer	WV	Limestone Handling													
Amos 1	WV	Lime Hydrate Expens													
Amos 2	WV	Lime Hydrate Expens													
Amos 3	WV	Lime Hydrate Expens													
Mountaineer	WV	Lime Hydrate Expens													
Mountaineer	WV	Lime Hydrate Handlin													
Clinch R1	VA	CO2 Allowance Cons													
Clinch R2	VA	CO2 Allowance Cons													
Mountaineer	WV	Polymer Handling													
		SO2 Allowance Cons													

I. Overview

The preparation of Appalachian Power Company's (APCo) and Wheeling Power Company's (WPCo) Expanded Net Energy Cost (ENEC) forecast requires a projection of APCo's and WPCo's internal load requirement. The internal load projection was developed by the AEPSC Economic Forecasting Department in conjunction with various groups across the AEP System. The AEP Production Costing Department developed the generation and off-system sales forecast.

II. Generation Forecast

The internal load forecast reflects an analysis of the economy and the unique factors that influence individual customers or customer classes that APCo and WPCo serve. A forecast of generation from APCo's generating units and purchased power was developed for the ENEC period to meet APCo's and WPCo's total system load obligations. Both APCo's and WPCo's generating units are operated along with the units of the other PJM members, to meet the total PJM load requirements on the most economical basis, based on price offers, subject to transmission limitations. Such operation was simulated in the development of the generation forecast by means of the PLEXOS® simulation model, a production costing computer program developed by Energy Exemplar. The generation forecast is prepared considering the impact of the projected fuel deliveries forecast, planned maintenance and other outages, random forced outages and any forecasted energy purchases.

III. Cost of Fuel Consumed

The cost of fuel consumed is based on the generation forecast and projected fuel deliveries for each of APCo's and WPCo's generating units.

Specifically, the cost of coal consumed for each of APCo's and WPCo's generating units is equal to the tons of coal consumed times the average unit cost of coal in fuel inventory. Since the cost of fuel consumed is developed on a monthly basis, the average cost of coal is defined as the weighted average cost of coal in inventory at the beginning of the month plus the projected fuel deliveries during the month. The tons of coal consumed are computed by *PLEXOS®*.

The cost of fuel consumed for the gas plants is also computed by *PLEXOS®*. The cost of gas consumed is based on the generation forecast and projected gas for each of APCo's gas units. The output of the gas units is multiplied by the expected price of natural gas.

The cost of coal handling is equal to the tons of coal consumed times the average unit cost of handling based on twelve months of historical averages.

IV. **Purchased Power**

APCo's purchased power forecast includes costs associated with planned purchases under long term agreements and market purchases. In this forecast, the planned purchases are for energy purchased from Summersville hydro, Ohio Valley Electric Corporation, renewable energy including solar and various wind farms. During the Forecast Period, APCo is projected to receive energy from the Camp Grove, Fowler Ridge, Grand Ridge, Beech Ridge and Bluff Point wind farms. Other purchases are assigned, based on cost, to either internal load or off-system sales via economic dispatch.

WPCo's purchased power forecast includes costs associated with market purchases.

V. **Consumables and Allowances**

The consumables and allowance expense forecast is based on projected emissions for APCo's and WPCo's generating units provided by PLEXOS®. The allowances are priced based upon the average cost of the allowance inventory.

VI. **Off System Sales**

OSS volume is a function of the Companies' forecasted generation and committed purchases (i.e., OVEC, solar and wind) from *PLEXOS®* and forecasted internal load on an hour-by-hour basis. An off-system sale is forecasted to occur in an hour when a company's total forecasted generation and committed purchases is greater than its internal load requirement.

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
DIRECT TESTIMONY
OF
MICHAEL J. ZWICK

DIRECT TESTIMONY OF
MICHAEL J. ZWICK
ON BEHALF OF APPALACHIAN POWER COMPANY AND
WHEELING POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA IN CASE NO. 22-_____________

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

A. My name is Michael J. Zwick. My business address is 500 Lee Street East, Charleston, WV, 25301. I am Vice President of Generating Assets for Appalachian Power Company ("APCo") and Wheeling Power Company ("WPCo"). APCo and WPCo are wholly-owned subsidiaries of American Electric Power Company, Inc. ("AEP").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I earned a Bachelor of Science degree in Electrical Engineering from Ohio University and completed a leadership development program at the Ohio State University Fisher College of Business. I joined Ohio Power Company in 1991 as a performance engineer at Muskingum River Plant where I advanced to supervisory positions in maintenance and operations. In 2005, I was promoted to Energy Production Manager at the Company's Philip Sporn Plant, where I was responsible for all aspects of plant operations. From 2007 through 2016, I was Plant Manager at multiple different power plants owned by AEP Ohio and AEP Generation Resources, including two combined cycle natural gas plants and three coal-fired power plants. The combined cycle plants I managed were Dresden Plant (665 MW) during its construction, and Waterford Plant (840 MW). The three coal-fired power plants I managed were Conesville Plant (1,590 MW), Muskingum River Plant (1425 MW), and Picway Plant (100 MW). In

2017, I was promoted to Managing Director of Ohio Generating Assets. In that role I was responsible for maintenance, operations, performance, safety, and environmental compliance of AEP's generating assets in Ohio as well as AEP's West Texas wind assets. I assumed my current position as Vice President Generating Assets for APCo and WPCo in October 2020.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS VICE PRESIDENT OF GENERATING ASSETS FOR APCO AND WPCO.

A. I am responsible for the safe, reliable, and economic operation of the fossil-fueled generating assets owned and operated by APCo. This includes the Amos and Mountaineer coal-fired power plants, as well as the gas-fired Ceredo (simple-cycle combustion turbines), Clinch River (gas-fired boiler), and Dresden (combined-cycle) power plants, and the Companies hydro facilities. Specifically, I plan, organize, coordinate, direct, and control plant activities, including the operations, maintenance, engineering, and construction of the plant facilities. I also oversee plant budgets and interface with other AEP functional groups such as Accounting, Regulatory, and Commercial Operations to ensure the needs of the generating plants are met. Additionally, I am responsible for any decommissioning, demolition, and disposition of generating assets owned or operated by APCo.

In addition, although WPCo does not operate the Mitchell plant, I help manage oversight of the plant on behalf of WPCo through interaction with AEP functional groups and my counterpart who is responsible for overall operation of the plant. I provide input to and oversight of decisions regarding the Mitchell plant asset investments, operating costs, and disposition.

Q. FOR WHOM ARE YOU PROVIDING TESTIMONY IN THIS PROCEEDING?

A. I am testifying on behalf of both APCo and WPCo. I shall refer to these entities collectively as the "Companies."

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to provide March 2021 through February 2022 ("Review Period") information about the Companies' fossil-fueled generating fleet, as ordered by the Commission in its August 31, 2018 order in Case No. 18-0503-E-ENEC, in Conclusion of Law, No. 9. I specifically discuss Net Capacity Factor ("NCF") and Equivalent Availability Factor ("EAF"), and the types of events that impact these generating unit statistics.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY TO ANY REGULATORY AGENCIES?

A. Yes. I have provided testimony before the Public Service Commission of West Virginia in Docket No. 21-0339-E-ENEC.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following exhibit:

- CONFIDENTIAL Company Exhibit MJZ – D1 – Fossil-Fueled Generating Fleet Review Period Equivalent Availability Factor

Q. PLEASE GIVE A BRIEF DESCRIPTION OF EACH OF THE PERFORMANCE METRICS MENTIONED ABOVE.

A. NCF is the ratio of a unit's actual net generation over a period to the net generation the unit would have produced had it been operated at its full load rating for the entire period. The capacity factor is obtained by dividing the actual net kWh generated in the operating period by the product of the net capability of the unit and the hours in the operating period. For instance, if a theoretical 100 MW unit were called upon by the market to operate at 100 MW (and was capable to do so) for an entire month, its NCF would be 100%. If the same theoretical were called upon by the market to operate at 50 MW for an entire month, its NCF would be 50%.

EAF is the percentage of time that a unit is capable of providing service, whether or not it is actually operating. Planned and unplanned outages as well as deratings reduce a unit's EAF. For example, a unit that was available to operate 100% of a time period but was derated to half load would have an EAF of 50%. However, when a unit is available to operate and not called upon by the Regional Transmission Operator, in this case PJM LLC (PJM), such instances do not affect the EAF as the unit is available but simply is not needed by the system. When a unit is not called upon to operate it does impact the NCF.

Q. WHAT TYPES OF EVENTS REDUCE THE NCF AND EAF OF A GENERATING UNIT?

A. Based on the definitions provided above, the NCF of a generating unit is reduced any time it is not generating at full-load capacity, whether the unit is online and operating at full load, or is shut down and not generating.

Multiple circumstances result in a unit operating at less than full load when online and generating energy. Such circumstances may include the unit being dispatched at less than full load by PJM, or equipment malfunctions that prevent the unit from achieving full load, but do not force the unit to cease operating.

Instances when a unit is in a shutdown condition due to scheduled or unplanned outages, or when the unit is available to operate but not called upon by PJM, also contribute to a lower NCF. All of these circumstances also reduce the EAF of a generating unit, with the exception of not being called upon to operate when available. This circumstance is driven by energy market conditions – not the ability of the unit to operate.

Q. CAN YOU PLEASE PROVIDE A FEW EXAMPLES OF POWER PLANT OPERATIONS, AND HOW EAF AND NCF ARE RELATED?

A. Yes. I offer the following simplified examples for a theoretical unit with a maximum rated capacity of 100 MW to describe how NCF and EAF are related, and how they are impacted by plant operations.

Assume a 100 MW unit is available for an entire month (no derates, no outages), and is called upon to operate at 100 MW for an entire month and is capable of doing so. In this instance the unit would have an NCF of 100% and an EAF of 100%.

If the same 100 MW unit was available to operate at full load (100 MW) for an entire month, but only dispatched to 50 MW for the entire month, if would have an NCF of 50% (operated at half load all month), and an EAF of 100% (was capable of operating at full load all month).

If such a unit were dispatched to 100 MW for half a month, then went into an outage for the other half a month, its NCF would be 50% (generated half the theoretical maximum MWh over the month), and its EAF would be 50% (100% available for half a month, 0% available during an outage).

And finally, if the unit was capable of operating at full load for an entire month but not called upon to operate by PJM (referred to as "reserve shutdown" or "down not required"), its NCF for that month is 0% (not generating) but its EAF is 100% (available at full load for the entire month).

Q. PLEASE PROVIDE THE NCF FOR THE COMPANIES' FOSSIL-FUELED GENERATING FLEET DURING THE REVIEW PERIOD.

A. See Figure 1 below, for the Companies' fossil-fueled generating fleet Review Period monthly and review period NCF.

Figure 1 – The Companies' Fossil-Fueled Generating Fleet NCF- March 2021 through February 2022.

APCo & WPCo
Fossil-Fueled Generating Fleet
Net Capacity Factor [%]
March 2021 through February 2022

Unit	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Review Period
Amos Unit 1	7.87	0.00	0.00	45.70	88.56	84.09	74.82	52.34	12.48	86.11	53.73	41.00	**45.73**
Amos Unit 2	0.00	37.00	63.55	77.43	84.84	49.82	5.80	0.00	0.00	46.92	49.52	7.45	**47.14**
Amos Unit 3	35.26	0.00	71.67	80.01	54.57	76.12	77.56	2.78	0.00	51.36	63.35	52.58	**47.14**
Amos Plant Rollup	**18.15**	**10.10**	**49.89**	**69.94**	**72.11**	**71.12**	**57.22**	**15.55**	**3.41**	**59.63**	**56.95**	**37.10**	**43.57**
Mitchell Unit 1	12.93	15.18	0.00	55.90	54.13	45.20	47.19	9.64	0.00	0.00	37.70	0.00	**23.27**
Mitchell Unit 2	9.10	10.72	65.03	51.02	71.11	77.10	55.23	45.54	29.93	63.42	55.82	38.96	**47.94**
Mitchell Plant Rollup	**10.99**	**12.92**	**32.93**	**53.43**	**62.73**	**61.35**	**51.26**	**27.82**	**15.16**	**32.12**	**46.88**	**19.73**	**35.77**
Mountaineer Unit 1	**69.43**	**69.76**	**67.23**	**88.56**	**90.40**	**89.97**	**28.36**	**0.00**	**0.00**	**58.51**	**82.26**	**57.67**	**58.64**
Coal Unit Rollup	**27.88**	**24.41**	**49.27**	**69.74**	**73.75**	**72.78**	**49.06**	**15.31**	**5.79**	**51.99**	**59.99**	**37.11**	**44.90**
Ceredo Unit 1	0.65	5.46	5.39	11.55	9.34	11.25	2.62	13.09	17.13	5.00	5.46	2.89	**7.51**
Ceredo Unit 2	0.65	5.17	3.02	11.52	8.61	10.90	3.02	12.86	17.79	4.90	5.48	2.90	**7.25**
Ceredo Unit 3	0.66	5.25	2.92	11.64	7.83	10.91	3.00	12.42	18.59	4.55	5.84	2.94	**7.22**
Ceredo Unit 4	0.65	5.19	4.25	12.32	8.66	11.25	3.09	13.18	18.02	4.99	5.80	2.87	**7.54**
Ceredo Unit 5	0.65	4.22	2.88	11.45	7.67	10.68	3.36	11.80	17.48	4.13	5.49	2.88	**6.90**
Ceredo Unit 6	0.65	4.22	2.88	10.84	8.98	10.72	2.96	12.18	17.16	4.10	5.46	2.85	**6.93**
Ceredo Plant Rollup	**0.65**	**4.92**	**3.55**	**11.55**	**8.52**	**10.95**	**3.01**	**12.59**	**17.70**	**4.61**	**5.59**	**2.89**	**7.23**
Clinch River Unit 1	0.00	0.00	7.60	6.41	3.44	11.29	0.24	1.93	4.52	0.00	0.00	1.91	**3.12**
Clinch River Unit 2	0.00	5.12	7.54	4.99	3.64	6.92	0.00	1.81	12.04	0.00	0.00	0.00	**3.51**
Clinch River Plant Rollup	**0.00**	**2.59**	**7.57**	**5.69**	**3.54**	**9.08**	**0.12**	**1.87**	**8.32**	**0.00**	**0.00**	**0.94**	**3.32**
Dresden 1A	88.96	52.41	86.26	81.96	79.94	80.93	27.46	11.98	94.28	91.22	94.25	90.88	**73.34**
Dresden 1B	88.37	51.95	85.93	81.57	79.51	80.39	27.36	12.32	93.59	90.84	96.53	91.07	**73.25**
Dresden 1S	76.69	47.59	76.33	76.22	74.09	78.49	24.75	9.75	86.94	74.93	86.95	76.59	**65.76**
Dresden Plant Rollup	**84.00**	**50.39**	**82.29**	**79.60**	**77.53**	**79.82**	**26.37**	**11.22**	**91.21**	**84.76**	**92.10**	**85.37**	**70.36**
Aggregate Rollup	**29.26**	**24.02**	**46.45**	**62.60**	**65.19**	**65.15**	**40.80**	**13.92**	**14.39**	**48.39**	**55.35**	**36.79**	**41.97**

Q. PLEASE SUMMARIZE THE COMPANIES' FOSSIL-FUELED GENERATING FLEET REVIEW PERIOD NCF.

A. The review period aggregated NCF for the Companies' fossil-fueled generating fleet shown in Figure 1 was 41.97%. This value was directly impacted by energy market conditions, causing them to be lower than the Review Period EAF which I discuss in more detail below.

Q. PLEASE PROVIDE THE REVIEW PERIOD EAF FOR THE COMPANIES' FOSSIL-FUELED GENERATING FLEET.

A. Please see CONFIDENTIAL Company Exhibit MJZ-D1, for the Companies' fossil-fueled generating fleet Review Period monthly and annual EAF, similar to what is provided for NCF in Figure 1.

Q. PLEASE SUMMARIZE THE COMPANIES' FOSSIL-FUELED GENERATING FLEET REVIEW PERIOD EAF PROVIDED IN CONFIDENTIAL COMPANY EXHIBIT MJZ-D1.

A. The review period aggregated annual EAF for the Companies' fossil-fueled generating fleet was higher than the Review Period NCF.

Q. BRIEFLY EXPLAIN WHY THE COMPANIES' FOSSIL-FUELED GENERATING FLEET AGGREGATED EAF IS HIGHER THAN THE NCF FOR THE REVIEW PERIOD.

A. As more fully described above, a generating unit's EAF is a measure of how often the unit is *capable* of generating at full load, whereas the NCF is a measure of actual output. Comparing the review period aggregate EAF to the review period aggregate NCF, one can see that the fossil-fueled generating fleet output was lower than it was capable of producing. This disparity is a result of instances when the Companies' generating units were either dispatched by PJM below their capable output, or in a shutdown state due to energy market conditions. NCF will never be higher than the EAF with the difference being the period of time during which the units are not selected by PJM to operate at all, or to operate at less than full capacity.

Q. PLEASE DESCRIBE THE OPERATIONAL CONDITIONS THAT AFFECT A GENERATING UNIT'S NCF AND EAF.

A. Aside from the level at which a generating unit is dispatched by PJM (which I discussed previously), operational conditions at each generating unit have a direct impact on NCF and EAF. Planned Outages, Maintenance Outages, and Forced outages are all different types of outages that reduce both NCF and EAF for the Companies' generating units.

Q. WHAT IS A PLANNED OUTAGE?

A. A Planned Outage is a generating unit outage that is scheduled well in advance and is of a predetermined duration, can last for several weeks, and occurs only once or twice a year. Typically, these events consist of a known scope of work and duration that is estimated prior to the outage being scheduled.

Q. HOW DO THE COMPANIES SCHEDULE PLANNED OUTAGES?

A. Planned Outages are scheduled well in advance (months and sometimes even years) due to significant scope, equipment lead time, engineering, and time out of operation. Such outages are planned in conjunction with PJM. The Companies schedule Planned Outages during the shoulder months attempting to avoid, to the extent practical, multiple units simultaneously in a Planned Outage.

Such Planned Outages are scheduled in coordination with Commercial Operations in order to comply with PJM requirements, the timing of which are discussed in more detail by Company witness Stegall.

Q. WHEN A UNIT IS IN A PLANNED OUTAGE, IS IT POSSIBLE TO QUICKLY RETURN THE UNIT TO SERVICE IF MARKET CONDITIONS CHANGE?

A. Generally, it is not. During a Planned Outage, a generating unit is often at least partly dismantled, often with pressure parts (parts that contain steam at very high pressures and temperatures when operating, such as boilers, turbines, etc.) taken apart to be inspected, maintained, and/or replaced. It is very difficult if not impossible to safely and quickly return a unit to service or deviate from the work plan for the outage, particularly when major equipment is disconnected/dismantled for repair during a Planned Outage.

Q. HOW DID THE COMPANIES' TAKE ADVANTAGE OF THE MARKET CONDITIONS TO ADDRESS EQUIPMENT CONDITIONS DURING THE REVIEW PERIOD?

A. The Companies took advantage of times when their units were not called upon to operate by PJM to perform maintenance work to repair equipment conditions that could have the potential to either cause a derate or require the units to be removed from service at a later time when PJM called upon units to operate. Undertaking this maintenance not only minimized downtime during peak market conditions, but minimized the cost of such work by avoiding potential overtime labor and expedited material delivery costs incurred with unplanned outages. The Companies' fossil-fueled generating fleet EAF, which I discuss below, is impacted by those maintenance outages. As part of APCo/WPCo's management team, I work in close coordination with the American Electric Power Service Corporation ("AEPSC"), and more specifically with its Commercial Operations organization as it relates to the actual level of generation from the plants. Company witness Stegall provides details on how Commercial Operations coordinates with PJM, which handles the economic dispatch of generating assets subject to PJM's jurisdiction.

Q. WHAT IS A MAINTENANCE OUTAGE?

A. A Maintenance Outage is an outage that is planned ahead of time, but it can be deferred beyond the end of the next weekend, and has a flexible start date that is determined by Commercial Operations and PJM. When operational or maintenance issues arise on a unit, the generating plant contacts Commercial Operations to explain the equipment issue. Company witness Stegall describes the process Commercial Operations follows to coordinate with PJM. A Maintenance Outage allows the equipment condition to be repaired to help prevent future deratings and Forced Outages.

Q. EXPLAIN WHY MAINTENANCE OUTAGES ARE IMPORTANT TO THE LONG-TERM OPERATIONS OF A POWER PLANT.

A. The Companies use Maintenance Outages as an opportunity to make needed equipment repairs that could be capable of causing deratings or forced outages at some point in the future had the repairs not been completed. Plant equipment conditions drive the need to perform maintenance activities outside of scheduled

Planned Outages. This type of outage also allows the Companies to help maintain unit availability during peak market conditions.

Q. WHAT IS A FORCED OUTAGE?

A. A Forced Outage results when a unit must be removed from service, either immediately or at some point prior to the end of the next weekend. When a unit experiences a Startup Failure, it is also considered a Forced Outage. Such outages are typically caused by equipment failures that occur when a unit is operating and prevent the unit from operating reliably.

Q. HOW EFFECTIVE WAS THE OUTAGE PLANNING PROCESS EMPLOYED BY THE COMPANIES'?

A. During the Review Period, all of the Companies' fossil-fueled generating units completed multiple scheduled outages to perform preventive maintenance, including those affected by energy market conditions which I previously discussed.

The Companies' fossil-fueled generating units experienced an average unplanned downtime of 14.5 days, or 3.99% during the Review Period. This low level of unplanned unit downtime is a direct result of the Companies' use of strategic outage planning.

Q. PLEASE SUMMARIZE YOUR DIRECT TESTIMONY.

A. My testimony in this case describes the operational conditions that occur at the Companies' fossil-fueled power plants, and the impact that those conditions have on the operation and availability of that fleet. The Companies appropriately planned maintenance for its fleet of power plants over the period in question, as planned and emergent maintenance work is required to maintain the reliability of the fleet at key periods of the year when they are anticipated to be needed by PJM to meet peak periods.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

APCo and WPCo
Fossil-Fueled Generating Fleet
Equivalent Availability Factor [%]
March 2021 Through February 2022

Unit	March	April	May	June	July	August	September	October	November	December	January	February	Review Period
Amos Unit 1	[redacted]												
Amos Unit 2													
Amos Unit 3													
Amos Plant Rollup													
Ceredo Unit 1													
Ceredo Unit 2													
Ceredo Unit 3													
Ceredo Unit 4													
Ceredo Unit 5													
Ceredo Unit 6													
Ceredo Plant Rollup													
Clinch River Unit 1													
Clinch River Unit 2													
Clinch River Plant Rollup													
Dresden 1A													
Dresden 1B													
Dresden 1S													
Dresden Plant Rollup													
Mitchell Unit 1													
Mitchell Unit 2													
Mitchell Plant Rollup													
Mountaineer Unit 1													
Aggregate Rollup													

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
DIRECT TESTIMONY
OF
JASON M. STEGALL

Company Exhibit
JMS-D

TESTIMONY OF
JASON M. STEGALL
ON BEHALF OF APPALACHIAN POWER COMPANY AND
WHEELING POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA ON REOPENING IN CASE NO. 22-____________

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

A. My name is Jason M. Stegall. My business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by American Electric Power Service Corporation (AEPSC) as Manager of Regulatory Pricing & Analysis. AEPSC supplies engineering, financing, accounting, planning, advisory, and other services to the subsidiaries of the American Electric Power (AEP) system, which includes Appalachian Power Company (APCo) and Wheeling Power Company (WPCo).

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I graduated from the Virginia Polytechnic Institute and State University with a Bachelor of Science degree in Accounting, in 1997. I earned my Master's in Business Administration from the Ohio State University in 2011. In addition, I attended the 2018 EEI Transmission and Wholesale Markets School.

I joined AEPSC in June 1997 as an Accountant in the Regulated Accounting Division of the Accounting Department. From 1997 to 2009, I held various positions in Accounting and Risk Management. In July 2009, I joined the Regulatory Services Department as a Regulatory Consultant in Customer and Distribution Services Support. In July 2010, I transferred to Regulated Pricing & Analysis where my role focused on developing cost-of-service studies and rate designs as well as other projects related to regulatory issues and proceedings, individual customer requests, and general rate matters. In December 2017, I was promoted into my current position.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.

A. My responsibilities include the oversight and support of all fuel and purchased power-related filings for the AEP System operating companies, supporting the AEPSC Fuel Procurement and AEPSC Commercial Operations organizations, and supporting traditional cost-of-service and rate design projects.

Q. FOR WHOM ARE YOU PROVIDING TESTIMONY IN THIS PROCEEDING?

A. I am providing testimony on behalf of both APCo and WPCo, (together, "the Companies").

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. I have testified before the Public Utilities Commission of Ohio, the Indiana Utility Regulatory Commission, the Public Service Commission of Kentucky, the Michigan Public Service Commission, the Oklahoma Corporation Commission, the Arkansas Public Service Commission, and the Public Utility Commission of Texas.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. To address the following:

- The Companies' participation in the PJM market
- PJM's role in determining which generation units are dispatched and which type of fuel is used
- The 2021 energy market and the effects of increased energy prices
- The projected capacity factors for the Companies' coal-fired generating units

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS FILING?

A. Yes. I am sponsoring the following exhibit:

- CONFIDENTIAL Company Exhibit JMS-D1: Projected Monthly Capacity Factors of the Companies' Fossil Fuel Units

MARKET OVERVIEW

Q. PLEASE DESCRIBE THE COMPANIES' DAILY ACTIVITIES IN THE PJM ENERGY MARKETS.

A. Every day, the Companies offer all of their available generating resources and purchase all of their expected load in the PJM Day-Ahead energy market. The offering of the Companies' generation resources involves submitting a large volume of data to PJM that includes unit commitment designation, offer curves that cover per-unit costs for the range of output from economic minimum to economic maximum, and market parameters. The market parameters include, but are not limited to, a unit's startup cost, startup time in hours, how quickly a unit can ramp-up energy production, and other characteristics defined in PJM protocols. PJM protocols are established in various documents such as the PJM tariff and the manuals published on www.pjm.com. This process involves a high level of coordination among AEPSC Commercial Operations personnel, AEPSC Fuel Procurement personnel and the Companies' management and generating unit personnel located at the individual plant sites. The purpose of this process is to provide the most up-to-date and accurate information to PJM prior to the market deadline. Commercial Operations relies on the generating unit personnel to provide the most up-to-date information on each generating unit's availability and capability. Commercial Operations relies on Fuel Procurement to provide the most up-to-date information on fuel availability and pricing, especially for natural gas which has prices that change on a daily basis. The daily process concludes when Commercial Operations compiles and submits all information required by PJM in advance of the Day Ahead market deadline.

Q. WHO ULTIMATELY DETERMINES THE LEVEL OF OUTPUT FOR A GENERATING UNIT?

A. PJM, through its economic dispatch model, determines the ultimate level of generation required to meet the load based on the units available in each hour and the economics of those units. In basic terms, PJM uses the offer information provided and arranges, or "stacks", the available units in economic order from the least cost to the highest cost. PJM's model then instructs, or dispatches, units to run by solving for the least cost solution to serve the level of load while factoring in transmission constraints. The PJM model is continuously updated in the Real-Time market to adjust for changing conditions in order to optimize the dispatch instructions that seek to provide the least cost solution to meet the RTO's load. This is beneficial to customers within the PJM footprint, including the Companies' West Virginia customers, because it ensures that the lowest cost units are prioritized to serve their load.

Q. PLEASE EXPLAIN WHAT IT MEANS TO SELF-SCHEDULE A UNIT.

A. As discussed above, the Companies provide a daily commitment designation for each of their generating units. The designations available are: Economic, Must-Run, Emergency, or Not Available. Economic units are committed and dispatched by PJM via its economic dispatch model described above. Must-run units, also referred to as self-scheduled units, are committed into the Day-Ahead market by their owner to run at their economic minimum, although the PJM dispatch model can dispatch them at a level above their economic minimum. Units are self-scheduled for economic or environmental reasons that are outside the scope of the PJM dispatch model. To provide some examples:

1. A coal-fired unit that is currently online might not be selected in the PJM Day-Ahead market to run next day if its commitment was designated as Economic. As a result, the unit would be shut down and would incur start-up costs the next time it was selected to run. This scenario typically happens on a weekend. A utility might instead elect to Must-Run, or self-schedule, the unit because by looking out further than just the next day, the utility feels that the market conditions are such that the unit would likely be economic and running over the longer term. By making this economic decision to Must-Run the unit, a utility is able to avoid the start-up costs and the additional wear and tear on the unit caused by excessive cycling of the unit on and off.

2. A unit might be designated as Must-Run, or self-scheduled, so that a utility can ensure the unit is running to meet an environmental testing compliance requirement.

It is possible, given a sufficiency of coal, to designate an available unit as Must-Run in order to consume more coal and achieve a higher capacity factor, even when the unit would not be selected to run under economic dispatch. The Companies would not, on their own, elect to pursue such a course of action, unless it were clear that the Commission wanted them to do so, after considering the interests that it is statutorily required to consider and had concluded that higher capacity utilization was more important than lower cost power. The Companies respect and do their best to comply with the directions of the Commission, but they do need clear direction on a matter of such consequence as more specifically addressed by Company witness Scalzo.

Q. DOES PJM PLACE ANY OBLIGATIONS ON THE AVAILABILITY OF GENERATING UNITS?

A. Yes. The first obligation is that any generating unit that is a capacity resource must offer its energy into the Day-Ahead energy market. Specifically, if a generating unit either sells its capacity through the PJM capacity auctions or supplies capacity through a Fixed Resource Requirement plan, it must offer its energy every day in the Day-Ahead energy market.

The second obligation is that all scheduled generating unit outages must be approved by PJM before the units are allowed to be taken out of service. This includes taking units out of service for either a planned or a maintenance outage, both of which are further discussed by Company witness Zwick. PJM also explicitly prohibits planned outages during PJM Peak Period Maintenance Season, which runs from the 24th Wednesday (June, 16th in 2021) through the 36th Wednesday (September 8th in 2021) of each year in order to ensure reliability during the summer season, when PJM typically experiences its highest annual peaks. While not scheduled, a generator is also required to report forced outages to PJM.

Q. DOES PJM PLACE ANY REQUIREMENTS ON THE AVAILABILITY OF FUEL FOR GENERATING UNITS?

A. Yes. In October 2021, PJM recognized the importance of coal and reagent inventories for coal-fired plants located within the RTO. In a revision to PJM Manual 13, PJM stated that it now has the ability to request a generating unit with less than ten days of coal to commit itself with an Emergency status until its coal inventory exceeds 21 days. [1]. This means that any unit below that 10-day limit may forgo market revenues during the winter season or, if it denied PJM's request and subsequently ran out of fuel or the reagents needed to manage its emissions, the unit may be subject to performance penalties if a market performance event occurred.

<u>THE COMPANIES' OPERATIONS IN PJM</u>

Q. PLEASE DESCRIBE HOW THE COMPANIES PARTICIPATE IN THE PJM ENERGY MARKETS.

A. As stated above, the Companies use their generating resources to meet their capacity obligations under a Fixed Resource Requirement plan and, therefore, offer all of their available generation into the PJM markets every day. In addition, they purchase all of their load each day. While they attempt to do this entirely through the Day-Ahead energy market, the PJM Real Time energy market exists to accommodate any changes in either expected generation or in expected load.

Q. HOW DO THESE TRANSACTIONS RESULT IN SALES TO AND PURCHASES FROM PJM?

A. In every hour for a given period, the Companies are buying and selling energy into the PJM Day-Ahead and Real Time energy markets. If one of the Companies purchases more energy than it sells into PJM in an individual hour, the result is a purchased power transaction. If one of the Companies sells more energy than it

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[1] The specific update to PJM Manual 13 addresses all steam units, although I have referred to the applicability of the revised rules to coal units because that is the focus of my testimony.

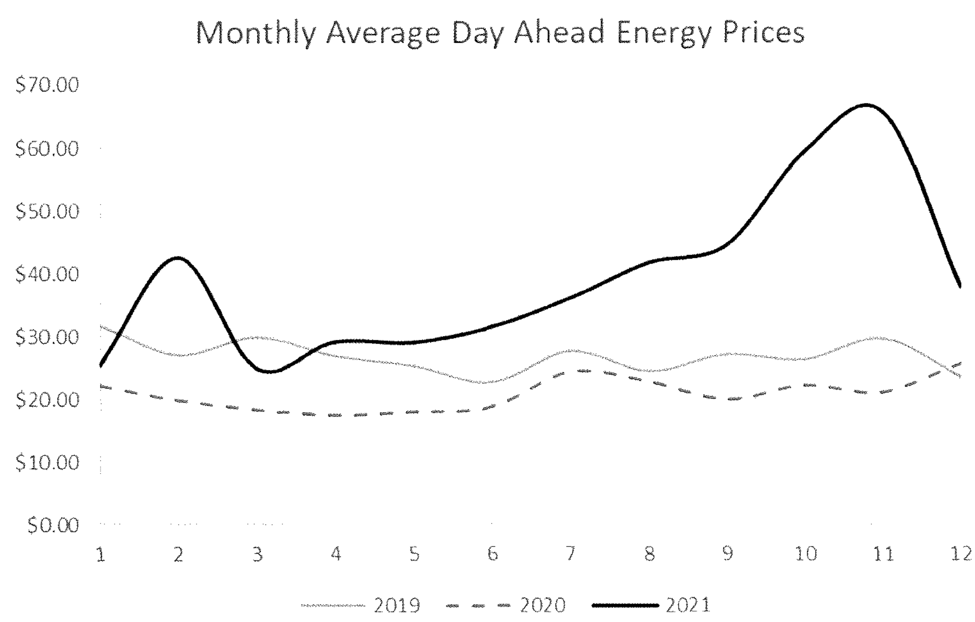
purchases in an individual hour, the result is an off system sale. It is possible for the Companies to have both sales to and purchases from PJM in a single month.

THE 2021 ENERGY MARKETS

Q. PLEASE DESCRIBE THE ENERGY MARKET DURING 2021.

A. Average energy prices increased throughout the year with a significant spike in prices from September 2021 through November 2021, which is highly unusual when compared to 2019 and 2020, as shown in Figure 1. The initial upward trend that occurred early in 2021 can be attributed to the resurgence of the economy following the COVID pandemic and economic downturn in 2020. The spike in energy prices beginning in September 2021 was the result of the price increases in natural gas that took place in the second half of 2021. Company witness Stutler addresses the natural gas markets in greater detail in his testimony.

Figure 1



Source: Verified Settlement Prices for the APCo load area, available on PJM.com

Q. WHAT IS THE SIGNIFICANCE OF A RISE IN NATURAL GAS PRICES?

A. In general, when natural gas prices rise, natural gas-fired generating units become the units on the margin in PJM and coal-fired generating units become more economic and are more likely to be dispatched by PJM. However, as discussed by witness Dial, the coal supply in the United States was not sufficient to resupply coal-fired generating units in advance of the 2021-2022 winter season. As a result, coal-fired generation units were not able to run at the level needed to take full advantage of the rise in natural gas prices.

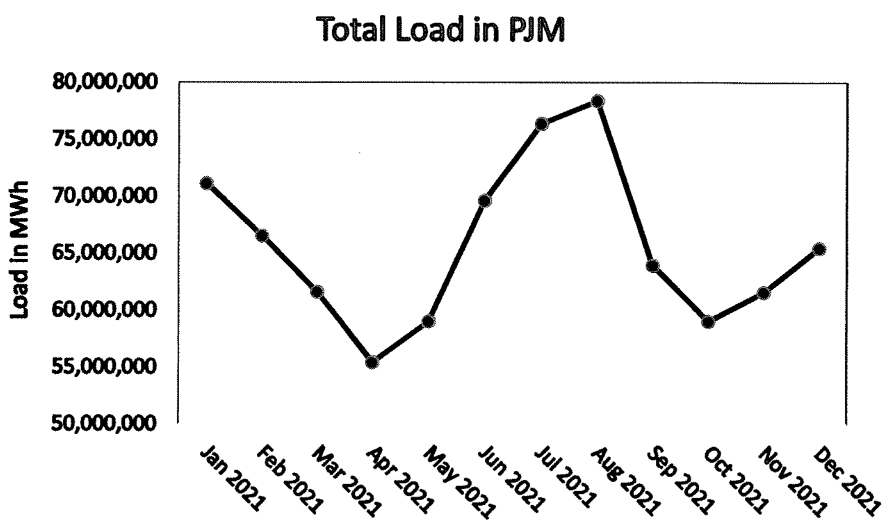
Q. WHAT WAS THE SIGNIFICANCE OF THE RISE IN PRICES DURING THE PERIOD OF SEPTEMBER THROUGH NOVEMBER?

A. This is one of the two periods in which generators typically schedule their planned outages. The spring and fall periods are chosen for planned outages because of expected lower demand during those months when the weather tends to be milder. If a generating unit scheduled a planned outage during this period, its operators would rely on that planned outage to make the major repairs or upgrades needed to maintain the viability of the units. Once a planned outage is started, it is difficult to restore the unit for service even if market prices have rapidly increased. Company witness Zwick provides more detail on outages in his testimony.

Q. WAS THE RISE IN ENERGY PRICES DUE TO AN UNUSUAL INCREASE IN LOAD IN PJM DURING THE LAST FOUR MONTHS OF 2021?

A. No. As shown in Figure 2, the total load in September 2021 sharply declined from the total load in August 2021. Furthermore, the rise in prices in both October and November 2021 was not the result of an increase in the amount of energy sold because total PJM load in October and November was below September levels.

Figure 2



Source: PJM Operations Summary Date available on PJM.com

Q. PLEASE EXPLAIN THE ANOMALY?

A. The anomaly is that prices typically do not rise in the fall without a specific weather-related incident. One would expect market prices to decline in the fall due to milder temperatures, resulting in less weather-based demand for energy. However, in 2021, despite the decline in load that typically happens in the fall, prices continued to rise. This increase reflected the underlying increase in fuel prices for natural gas-fired generating units, which are typically the marginal units in PJM.

Q. WOULD IT HAVE BEEN REASONABLE FOR THE COMPANIES TO OFFER THEIR UNITS INTO PJM IN A MANNER THAT WOULD HAVE RESULTED IN THEM RUNNING AT A HIGHER LEVEL DURING THIS PERIOD?

A. Not during that period. The Companies take into account all available information regarding the economics and operating characteristics of their coal-fired generating units when offering them into the PJM energy markets. During that period, the availability of the Companies' coal-fired units were limited by both their being out of service for needed maintenance work (as discussed by Company witness Zwick) and the lack of sufficient coal supply (as discussed by Company witness Dial). As mentioned above, the Companies' generating units were subject to new rules in PJM where, if their coal supply fell below 10 days, they may have been asked to change their market status to one where PJM would only dispatch them in situations where they were needed for reliability. Even if the Companies had rejected the request from PJM, there was the high likelihood that all of the Companies' coal-fired generating units would run out of coal during the winter season and expose the Companies' customers, including those in West Virginia, to higher energy prices to satisfy their needs, in addition to capacity performance penalties.

Q. WHY IS THE WINTER SEASON SIGNIFICANT FOR THE COMPANIES?

A. APCo is a winter peaking utility and needs its generating resources to be available to meet its winter weather-driven demand. From 2018 through 2020, all of APCo's annual peaks have occurred in January. WPCo peaks are only about 8-10% of APCo's and do not occur consistently because their load is primarily industrial and relatively stable. As a result, APCo is the primary entity driving costs for the Companies' West Virginia customers.

Q. COULD THE COMPANIES HAVE RUN THEIR GENERATING UNITS AT A 69 PERCENT CAPACITY FACTOR DURING 2021?

A. No. Of course, the Companies were not aware of the Commission's order with regard to a 69% capacity factor until September 2, 2021. But if the Companies had forgone all planned and maintenance outages during 2021 and run their coal-fired units at a 69% capacity factor, all the units would have run out of coal before the end of the year. My estimate shows that Mountaineer, with no outages and running at a 69% capacity, would have run out of coal in November 2021, and been unavailable for the 2021 winter season. Amos, forgoing the spring 2021 outage at some of its units, would have fallen below PJM's 10-day inventory level in June and would have been unable to operate at all during the remainder of the summer and into the fall. Finally, Mitchell, forgoing a planned outage of Unit 2 in spring 2021, would have fallen below PJM's 10-day inventory level in July and would have remained unavailable for the remainder of the summer and into the fall.

After the Commission's September 2, 2021 Order, the Companies could not have run their coal-fired units at a 69% capacity factor from September 2021 through February 2022 due to the limited availability of coal, as described by Company witness Dial, and the outages for maintenance work, as described by Company witness Zwick.

NET CAPACITY FACTORS

Q. WHAT ARE THE PROJECTED NET CAPACITY FACTORS FOR THE COMPANIES' FOSSIL FUEL PLANTS DURING THE FORECAST PERIOD?

A. The net capacity factors in Exhibit JMS-D1 reflect the forecasted generation values provided by Company witness Sloan in Exhibit SAS-D4 and the nameplate capacity values for the applicable generating units. The projected summary values for the Companies' coal-fired units are provided in Table 1 below along with their projected equivalent availability factors.

Table 1

Unit Name	NCF	EAF
Amos 1	32.7%	62.4%
Amos 2	31.6%	59.0%
Amos 3	50.5%	78.0%
Mountaineer	60.1%	87.9%
Mitchell 1	16.8%	53.6%
Mitchell 2	30.5%	64.2%

Q. PLEASE EXPLAIN WHY THE FORECASTED CAPACITY FACTORS FOR THE COMPANIES' COAL UNITS ARE NOT PROJECTED TO REACH THE TARGET LEVEL IDENTIFIED BY THE COMMISSION IN CASE NO. 21-0339-E-ENEC.

A. As stated above, the Companies' coal units are subject to both economic and operational limitations regarding their dispatch. The capacity factors shown above and presented in detail in Exhibit JMS-D1 already reflect any limitations to unit availability for forecasted outages. Once the outages are taken into account, the Companies' forecast assumes that all generating units are going to be dispatched on an economic basis based on unit variable costs. I want to emphasize, however, that the Companies do not manage, and historically have not managed, to any forecast of owned- generation or projected levels of market purchase of energy. Rather, as I have explained above, the Companies offer their units into the PJM energy market on a daily basis, after giving due consideration to all appropriate circumstances, so as to minimize the cost to serve their customers' loads.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Net Capacity Factors

Unit Name	State	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Total
Amos 1	WV	[redacted]												
Amos 2	WV	[redacted]												
Amos 3	WV	[redacted]												
Total Amos		[redacted]												
Ceredo 1	WV	[redacted]												
Ceredo 2	WV	[redacted]												
Ceredo 3	WV	[redacted]												
Ceredo 4	WV	[redacted]												
Ceredo 5	WV	[redacted]												
Ceredo 6	WV	[redacted]												
Total Ceredo		[redacted]												
Clinch R1	VA	[redacted]												
Clinch R2	VA	[redacted]												
Total Clinch River		[redacted]												
Dresden	OH	[redacted]												
Mountaineer	WV	[redacted]												
Mitchell 1	WV	[redacted]												
Mitchell 2	WV	[redacted]												
Total Mitchell		[redacted]												

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
DIRECT TESTIMONY
OF
RUBY A. GREENHOWE

DIRECT TESTIMONY OF RUBY A. GREENHOWE ON BEHALF OF APPALACHIAN POWER COMPANY AND WHEELING POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF WEST VIRGINIA IN CASE NO. 22-

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

A. My name is Ruby A. Greenhowe. My business address is 500 Lee Street, East, Charleston, West Virginia. I am employed by Appalachian Power Company ("APCo") as a Regulatory Consultant Principal – Regulatory Services for West Virginia.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I attended West Virginia Institute of Technology and graduated from Mountain State University with a Bachelor of Science Degree in Organizational Leadership and a Master of Science Degree in Strategic Leadership. I am certified as a Project Management Professional.

I have 33 years of experience with the American Electric Power Company, Inc. ("AEP") system. I was first employed by APCo in 1988 as a Customer Services Representative in the customer accounting department in Montgomery, West Virginia. My responsibilities included assisting customers with billing and service related inquiries and processing credit and collection orders. I worked in a similar capacity in the Oak Hill, Beckley, and Hurricane, West Virginia locations through 1997. In 1998, I became a lead associate in the Hurricane Customer Solutions Center where I provided customer service support to employees and customers. In 2003, I was promoted to Commercial & Industrial Associate, where I provided assistance to AEP's commercial customers. I was promoted to Customer Solutions Center Supervisor in 2006. In February 2010, I was promoted to Supervisor of Administrative Services at the John Amos Plant where my responsibilities included administration and management of the plant's accounting and office functions. In July 2010, I was promoted to the position of Regulatory Consultant in APCo's Regulatory Services Department in Charleston, West Virginia. In 2018, I assumed my current position of Regulatory Consultant Principal.

Q. WHAT ARE YOUR DUTIES AS A REGULATORY CONSULTANT PRINCIPAL?

A. My current duties include performing various rate and regulatory activities for APCo and Wheeling Power Company ("WPCo") in West Virginia, including the preparation of Expanded Net Energy Cost ("ENEC") filings.

Q. FOR WHOM ARE YOU SUBMITTING TESTIMONY?

A. I am submitting testimony on behalf of both APCo and WPCo. I shall refer to these entities individually as APCo or WPCo, or jointly as the "Companies."

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN ANY REGULATORY PROCEEDINGS?

A. Yes. I submitted testimony and testified before the Commission in several cases, including Case No. 19-0396-E-P. I submitted testimony to the Commission in Case No. 21-0339-E-ENEC and in previous ENEC cases.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is as follows:

- To present an overview of the Companies' ENEC recovery position;
- To provide the forecast and actual jurisdictional and class demand and energy allocation factors;
- To review the ENEC recovery position at February 28, 2022; and
- To provide the development of ENEC rate components that would be required to fully recover ENEC expenses for the twelve months ending August 31, 2023 ("Forecast Period").

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring the following Exhibits:

- Company Exhibit RAG-D1, Monthly Internal Load Forecast
- Company Exhibit RAG-D2, Forecast Jurisdictional Allocation Factors
- Company Exhibit RAG-D3, Forecast Customer Class Energy Allocation Factors
- Company Exhibit RAG-D4, Forecast Customer Class Demand Allocation Factors
- Company Exhibit RAG-D5, Proposed ENEC Rate Factors

Q. WHAT CHANGE IN ANNUAL ENEC REVENUE IS NEEDED IN THIS PROCEEDING?

A. The needed increase in the annual ENEC revenue requirement is approximately $296.6 million.

Q. PLEASE DESCRIBE HOW THIS INCREASE IN THE ANNUAL ENEC REVENUE REQUIREMENT WAS DETERMINED.

A. The increase in the annual ENEC revenue requirement is the sum of the in-period estimated amount and the prior (or review) period amount plus any in-period adjustments. The in-period amount is calculated by using the forecast period billing determinants and previously approved ENEC rates to determine any over- or under-recovery for the forecast period. In this case, I used ENEC rates that were effective March 2, 2022 as set in the Companies' 2021 ENEC case.

Q. ARE THE COMPANIES REQUESTING A CHANGE IN ENEC RATES?

A. Yes. The Companies are requesting an increase in ENEC annual revenue of approximately $296.6 million.

Q. FOR WHAT TIME PERIOD HAVE YOU PREPARED FORECAST JURISDICTIONAL AND CLASS DEMAND AND ENERGY ALLOCATION FACTORS?

A. I have prepared forecasted jurisdictional and class demand and energy allocation factors for the Forecast Period, September 1, 2022 through August 31, 2023.

Q. IS THE METHODOLOGY FOR DEVELOPING THE JURISDICTIONAL AND CLASS ALLOCATION FACTORS CONSISTENT WITH THE PROCEDURES USED IN PREVIOUS ENEC PROCEEDINGS?

A. Yes it is. The determination of these allocation factors is based upon the demand and energy forecasts provided by the Resource Planning & Operations Analysis and the Corporate Planning and Budgeting Sections of the American Electric Power Service Corporation and employs the same methodology used by the Companies in previous cases.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE COMPANIES' PROJECTED JURISDICTIONAL DEMAND AND ENERGY ALLOCATION FACTORS FOR APCO.

A. The jurisdictional allocation factors for APCo are based on the forecast of demand and energy requirements for the Forecast Period provided to me by the Economic Forecasting Department, as shown in Company Exhibit RAG-D1. This forecast projects sales to ultimate and wholesale customer groups in West Virginia, Virginia, and Tennessee and includes an aggregation of system losses. Company Exhibit RAG-D2 provides the calculation of the jurisdictional demand and energy allocation factors used to allocate APCo's projected ENEC-related costs to the West Virginia jurisdiction.

Q. HOW ARE THE COMPANIES' DEMAND AND ENERGY ALLOCATIONS APPORTIONED AMONG CLASSES?

A. The apportionment was based on actual demand and energy data for the twelve-month period ended December 31, 2021. These allocation factors are shown in Company Exhibit RAG-D3 and Company Exhibit RAG-D4.

Q. ARE THE METHODOLOGIES FOR DEVELOPING THE JURISDICTIONAL AND CLASS ALLOCATION FACTORS CONSISTENT WITH THE PROCEDURES USED IN PREVIOUS ENEC PROCEEDINGS?

A. Yes, the same methodologies were used in the development of the jurisdictional and class ENEC allocation factors as were used in previous ENEC cases.

Q. WHAT IS THE ACTUAL ENEC RECOVERY POSITION AS OF FEBRUARY 28, 2022?

A. The Companies have recorded an ENEC under-recovery of $216 million as of February 28, 2022, as shown in Company witness Short's testimony.

Q. PLEASE GENERALLY DESCRIBE THE METHODOLOGY USED TO DEVELOP THE PROPOSED ENEC FACTORS.

A. The development of the proposed ENEC factors began with a forecast of the annual components of costs and revenues to be included in the ENEC. To the extent the ENEC costs are associated with multiple jurisdictions, as is the case for APCo, they were first allocated to West Virginia and then to the customer classes or individual customers, based on appropriate demand and energy relationships. Once the ENEC components were assigned to a class of customers, forecast billing determinants for each customer class were used to arrive at the individual demand or energy factors appropriate to recover each class's ENEC.

Q. IS THE METHODOLOGY USED TO DEVELOP THE PROPOSED ENEC FACTORS THE SAME AS THE METHODOLOGY USED IN THE COMPANIES' 2021 ENEC PROCEEDING?

A. Yes.

Q. HAVE THE COSTS AND REVENUES RELATED TO WPCO BEEN INCLUDED IN YOUR ENEC CALCULATION?

A. Yes, they have. I obtained the WPCo costs and revenues from Company witness Sloan.

Q. HAVE YOU PREPARED AN EXHIBIT SUMMARIZING THE PROPOSED ENEC FACTORS FOR APCO AND WPCO?

A. Yes, I have. Company Exhibit RAG-D5 reflects the ENEC factors for APCo and WPCo that would be in place with an annual increase of approximately $296.6 million in ENEC revenue.

Q. HAVE YOU PREPARED REVISED TARIFF SHEETS INCORPORATING THE COMPANIES' PROPOSED ENEC FACTORS?

A. No. The Companies will provide updated tariff sheets upon the resolution of this case.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Appalachian Power Company/Wheeling Power Company
Monthly Internal Load Forecast
September 2022 Through August 2023

Total Company Internal Energy (GWH)	September	October	November	December	January	February	March	April	May	June	July	August	12 Months August 2023
Residential	696.9	638.6	879.0	1,239.9	1,408.2	1,137.4	966.4	712.4	668.0	718.5	982.8	896.1	10,944.2
Commercial	468.8	475.5	500.5	474.6	526.7	469.4	471.9	412.4	478.9	491.5	593.7	534.0	5,897.6
Total Industrial	729.3	777.0	810.8	714.2	714.2	699.7	749.6	688.7	762.0	731.0	781.8	754.7	8,912.9
Total Other Ultimate	68.9	70.9	77.1	72.6	76.5	72.4	73.0	64.3	71.6	68.8	73.4	69.2	858.7
Total Ultimate Sales	1,963.9	1,962.0	2,267.4	2,501.2	2,725.6	2,378.9	2,260.9	1,877.7	1,980.5	2,009.7	2,431.7	2,254.0	26,613.4
Kingsport Power Company	125.3	117.1	132.2	160.1	172.4	164.5	146.8	130.1	123.2	128.2	157.0	143.1	1,699.9
Municipals, Cooperatives, Other Sales	89.8	82.7	85.7	97.4	106.3	93.7	89.7	79.3	83.5	92.5	103.4	102.3	1,106.1
Total Sales-for-Resale	215.1	199.7	217.9	257.5	278.7	258.2	236.5	209.4	206.7	220.7	260.4	245.4	2,806.0
Total Internal Sales	2,179.0	2,161.7	2,485.2	2,758.7	3,004.3	2,637.1	2,497.4	2,087.1	2,187.1	2,230.4	2,692.1	2,499.4	29,419.4
Total Losses (VA and WV)	192.4	194.0	98.1	244.1	266.3	233.1	222.4	184.5	110.4	178.7	66.8	222.7	2,213.5
Kingsport Power Company Losses	5.0	4.7	5.3	6.4	6.9	6.6	5.9	5.2	4.9	5.1	6.3	5.7	68.0
Total Internal Energy	2,376.3	2,360.4	2,588.6	3,009.2	3,277.4	2,876.8	2,725.7	2,276.8	2,302.5	2,414.3	2,765.1	2,727.8	31,700.9
Internal Peak Demand (MW)	4,970	4,533	5,249	5,676	6,705	6,874	4,981	4,332	4,360	4,664	5,311	5,276	5,244.35
Kingsport Demand (MW)	263	225	279	296	369	338	240	236	240	227	266	246	268.79

West Virginia Monthly Internal Load	September	October	November	December	January	February	March	April	May	June	July	August	12 Months August 2023
Residential	297.7	274.7	371.0	538.5	616.6	502.8	421.7	307.7	285.6	312.4	423.7	393.5	4,745.9
Commercial	244.5	252.5	256.9	246.2	275.4	243.4	247.1	215.1	248.7	256.9	306.0	278.3	3,071.1
Total Industrial	329.8	360.2	377.5	331.6	337.6	319.4	343.5	303.1	336.2	319.1	349.6	337.3	4,044.9
Total Other Ultimate	2.3	2.7	3.0	3.1	3.1	2.5	2.6	2.1	1.9	1.7	1.9	2.0	28.851
Loss of Century Load													-
Total Ultimate Sales	874.4	890.1	1008.4	1119.4	1232.6	1068.0	1015.0	828.0	872.4	890.2	1081.1	1011.1	11,890.8
Sales-for-Resale	3.6	3.7	4.5	5.5	6.4	6.1	5.3	3.9	3.1	3.6	4.1	4.0	53.8
Total Internal Sales	877.9	893.8	1012.9	1125.0	1239.0	1074.1	1020.3	831.9	875.5	893.8	1085.3	1015.2	11,944.6
Total Losses	99.1	81.1	20.0	114.1	130.0	116.7	78.6	79.6	44.3	93.0	57.0	104.7	1,018.3
Total Internal Energy	977.0	974.9	1032.9	1239.1	1369.0	1190.8	1098.9	911.5	919.8	986.8	1142.3	1119.9	12,962.8
West Virginia CP Demand	2,023	1,912	2,081	2,178	2,726	2,882	1,978	1,784	1,744	1,991	2,244	2,188	2,144

Virginia Monthly Internal Load	September	October	November	December	January	February	March	April	May	June	July	August	12 Months August 2023
Residential	399.2	363.9	508.0	701.4	791.6	634.7	544.7	404.7	382.4	406.1	559.1	502.5	6,198.3
Commercial	224.2	223.0	243.6	228.4	251.3	226.0	224.8	197.2	230.2	234.6	287.7	255.7	2,826.6
Total Industrial	399.5	416.7	433.3	382.6	376.6	380.3	406.0	385.6	425.8	411.8	432.2	417.4	4,868.0
Total Other Ultimate	66.6	68.2	74.1	69.5	73.5	69.9	70.4	62.2	69.7	67.1	71.5	67.2	829.8
Total Ultimate Sales	1089.5	1071.9	1259.0	1381.8	1493.0	1310.9	1245.9	1049.7	1108.1	1119.5	1350.6	1242.9	14,722.6
Cooperatives	14.0	12.9	16.1	20.1	22.9	18.5	16.5	12.9	13.8	16.2	19.5	18.0	201.4
Municipals	44.3	39.8	41.2	47.0	51.0	44.7	43.6	38.4	41.4	46.8	51.4	50.9	540.7
State Agencies	27.9	26.3	23.9	24.6	26.0	24.4	24.3	24.2	25.1	25.9	28.3	29.3	310.2
Total Sales-for-Resale	86.2	79.0	81.1	91.8	99.9	87.6	84.4	75.4	80.4	88.9	99.3	98.2	1,052.3
Total Internal Sales	1175.7	1150.9	1340.1	1473.6	1592.8	1398.5	1330.3	1125.1	1188.4	1208.4	1449.8	1341.1	15,774.9
Total Losses	93.2	112.9	78.1	130.0	136.3	116.4	143.8	104.9	66.1	85.8	9.7	118.0	1,195.2
Total Internal Energy	1268.9	1263.8	1418.3	1603.6	1729.1	1514.9	1474.2	1230.0	1254.6	1294.2	1459.5	1459.1	16,970.1
Virginia CP Demand	2,684	2,396	2,889	3,202	3,611	3,654	2,762	2,312	2,377	2,446	2,801	2,842	2,831

Wheeling Monthly Internal Load	September	October	November	December	January	February	March	April	May	June	July	August	12 Months August 2023
Wheeling Residential	29.7	23.1	26.9	40.3	50.6	35.9	34.3	19.4	27.2	30.5	38.8	38.3	395.3
Wheeling Commercial	33.0	31.2	28.5	31.3	36.1	29.6	32.1	21.4	33.9	33.8	36.8	37.4	385.1
Wheeling Industrial	302.2	323.0	319.1	284.0	314.7	293.8	336.2	325.1	356.5	309.6	312.6	321.5	3,798.1
Wheeling Other Ultimates	0.4	0.5	0.6	0.6	0.6	0.5	0.5	0.4	0.4	0.3	0.4	0.4	5.5
Total Ultimate Sales	365.4	377.7	375.0	356.3	402.0	359.8	403.0	366.4	418.0	374.2	388.6	397.6	4,584.0
													-
Sales-for-Resale													-
Total Internal Sales	365.4	377.7	375.0	356.3	402.0	359.8	403.0	366.4	418.0	374.2	388.6	397.6	4,584.0
Total Losses	22.1	17.4	14.2	58.4	20.8	13.9	13.8	2.0	-33.5	11.6	4.5	13.6	158.8
Total Wheeling Ultimate Sales	387.5	395.1	389.2	414.7	422.8	373.7	416.8	368.4	384.5	385.8	393.1	411.2	4,742.8
Wheeling CP Demand	644	574	584	628	643	620	602	553	588	647	655	660	616

West Virginia Including APCo & WPCo Monthly Internal Load	September	October	November	December	January	February	March	April	May	June	July	August	12 Months August 2023
Residential	327.5	297.7	397.9	578.9	667.2	538.7	456.0	327.1	312.8	342.9	462.5	431.8	5,141.2
Commercial	277.5	283.7	285.4	277.5	311.5	273.0	279.2	236.5	282.6	290.7	342.8	315.7	3,456.2
Industrial	632.0	683.2	696.6	615.6	652.3	613.1	679.7	628.2	692.6	628.7	662.2	658.7	7,843.1
Other Ultimates	2.7	3.2	3.5	3.7	3.7	3.0	3.1	2.5	2.3	2.1	2.2	2.4	34.4
Loss of Century Load	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Ultimate Sales	1239.7	1267.9	1383.4	1475.7	1634.6	1427.8	1418.0	1194.4	1290.4	1264.4	1469.7	1408.7	16,474.8
													16,474.8
Sales-for-Resale	3.6	3.7	4.5	5.5	6.4	6.1	5.3	3.9	3.1	3.6	4.1	4.0	53.8
Total Losses	121.2	98.5	34.1	172.5	150.8	130.6	92.4	81.6	10.8	104.6	61.5	118.3	1,177.0
Total Ultimate Sales	1364.5	1370.0	1422.1	1653.8	1791.9	1564.5	1515.7	1279.9	1304.3	1372.6	1535.4	1531.1	17,705.6
APCo & WPCo CP Demand	2,668	2486	2665	2807	3369	3502	2580	2337	2331	2638	2899	2848	2,761

Appalachian Power
Forecast Jurisdictional Energy Allocation Factors
For the Twelve Months Ending August 31, 2022

Jurisdiction	MWH Sales	Loss Factor	MWH Load	Energy Allocation Factor
State of West Virginia				
WV Retail	11,890,786	1.085352	12,905,691.31	0.407109
Total Retail	11,890,786		12,905,691	0.407109
WV Sales for Resale Distribution	53,798	1.062410	57,155	0.001803
Total West Virginia	11,944,584		12,962,847	0.408912
State of Virginia				
Virginia Retail / Locals	14,722,595	1.076721	15,852,128.16	0.500054
Virginia Sales for Resale	1,052,304	1.062410	1,117,979	0.035267
Total Virginia	15,774,899		16,970,107	0.535320
State of Tennessee				
Kingsport Power	1,699,920	1.039990	1,767,900	0.055768
Total Company	29,419,403		31,700,853	1.000000

Appalachian Power
Forecast Jurisdictional Demand Allocation Factors
For the Twelve Months Ending August 31, 2022

Jurisdiction	MW Load (12 CP Average)	Loss Factor	MW Load (12 CP Average)	Demand Allocation Factor
State of West Virginia				
WV Retail	1,930	1.1061	2,135	0.407043
Total Retail	1,930		2,135	0.407043
WV Sales for Resale Distribution	8.96	1.0793	9.67	0.001843
Total West Virginia	1,939		2,144.34	0.408886
State of Virginia				
Virginia Retail / Locals	2,401	1.1053	2,653	0.505923
Virginia Sales for Resale	169	1.0561	178.0	0.033938
Total Virginia	2,569		2,831	0.539860
State of Tennessee				
Kingsport Power	256	1.0503	269	0.051253
Total Company	4,764		5,244	1.000000

APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
FORECAST ENEC - ENERGY RELATED
ALLOCATED TO CUSTOMER CLASSES
SEPTEMBER 2022 - AUGUST 2023

(1) TARIFF SCH.	(2) ENERGY ALLOCATION FACTOR	(3) ENEC - ENERGY RELATED (ENERGY ENEC X Col.2) ($)
RS	0.319242	152,519,350
SWS	0.004816	2,300,636
SGS Sec	0.016624	7,942,415
SGS Pri	0.000049	23,555
SS Sec	0.014470	6,912,977
SS Pri	0.001948	930,878
SS AF Pri	0.000338	161,666
GS Sec	0.149447	71,399,083
GS Pri	0.018156	8,674,171
GS Sub	0.003108	1,484,710
GS Trans	0.000585	279,709
GS AF	0.000104	49,851
LCP Sec	0.006294	3,006,926
LCP Pri	0.062660	29,936,034
LCP Sub	0.079338	37,904,094
LCP Trans	0.266312	127,231,849
IP Sec	0.000000	0
IP Pri	0.000423	202,079
IP Sub	0.006984	3,336,444
IP Trans	0.016442	7,855,207
OL	0.004523	2,160,817
SL	0.001734	828,499
SCC	0.000064	30,749
SCD	0.010612	5,069,816
SCI	0.011002	5,256,125
SCJ	0.000604	288,796
SCK	0.004120	1,968,341
TOTALS	1.000000	477,754,778
		477,754,778

ENERGY-RELATED ENEC 12 MONTHS ENDING JUNE 30, 2021	APCO	WPCO
Fossil Generation	$549,091,303	$42,735,036
Fuel Handling	$37,857,651	$3,088,273
Purchased Power OVEC (Energy)	$38,286,006	$0
Purchased Power PPA (Energy)	$6,712,708	$0
Purchased Power Market Purchases (Energy)	$204,044,333	$91,043,498
Purchased Power Wind	$82,381,621	-
Purchased Power - Solar (Energy)	$1,303,389	
PJM Ancillaries	$8,412,412	$1,322,663
Transmission Losses	$10,835,851	$614,482
Consumables and Allowance Expenses	$38,768,785	$4,027,782
FORECAST ENEC -ENERGY	$977,694,057	$142,831,735
Less:		
Transmission Revenue (Energy)	-	-
Off-System Sales Revenue COGS (Energy)	$77,299,267	3,750,267
Off-System Sales Margin (Energy)	$26,764,798	1,889,551
Gain/(Loss) on Sale of Allowances (Energy)	$1,501,000	567,667
FORECAST ENEC -ENERGY - Adjusted	$872,128,992	$136,624,250
WV ENERGY ALLOCATION FACTOR	0.407109	1.000000
WV RETAIL ENEC -ENERGY RELATED	$355,051,253	$136,624,250
Less:		
Transmission Agreement Costs (Energy)	$106,295	
Transmission Adjusted Allocation Factor	0.445847	
	$47,391	
Less:		
Sale of Renewable Energy Credits	$13,873,333	
Total APCo and WPCo ENEC - ENERGY RELATED		$477,754,778.43

APPALACHIAN POWER COMPANY / WHEELING POWER COMPANY
FORECAST ENEC - DEMAND RELATED
ALLOCATION TO CUSTOMER CLASSES
SEPTEMBER 2022 - AUGUST 2023

(1) TARIFF SCH.	(2) DEMAND ALLOCATION FACTOR	(3) ENEC - DEMAND RELATED (DEMAND ENEC X COL.2)
RS	0.439715	87,215,947
SWS	0.006063	1,202,505
SGS Sec	0.014882	2,951,828
SGS Pri	0.000046	9,039
SS Sec	0.015929	3,159,423
SS Pri	0.001903	377,544
SS AF Pri	0.000399	79,082
GS Sec	0.139070	27,584,099
GS Pri	0.015474	3,069,249
GS Sub	0.003173	629,324
GS Trans	0.000471	93,438
GS AF	0.000100	19,776
LCP Sec	0.005187	1,028,917
LCP Pri	0.051867	10,287,606
LCP Sub	0.073392	14,556,952
LCP Trans	0.199083	39,487,483
IP Sec	0.000000	-
IP Pri	0.000239	47,503
IP Sub	0.004213	835,589
IP Trans	0.009125	1,809,979
OL and SL	0.000173	34,269
SPECIAL CONTRACT C	0.000465	92,304
SPECIAL CONTRACT D	0.008071	1,600,928
SPECIAL CONTRACT I	0.007682	1,523,740
SPECIAL CONTRACT J	0.000665	131,979
SPECIAL CONTRACT K	0.002612	518,003
	1.00	$198,346,506
		TRUE

DEMAND-RELATED ENEC 12 MONTHS ENDING AUGUST 31, 2022	APCO	WPCO
Fuel Handling (Demand)	$ 14,304,936	$ -
Purchased Power Cost - Non Affiliated	$ 64,982,160	$ -
PJM Ancillaries	$ 1,126,948	$ 649,470
FTR Revenue Net Of Congestion Costs	$ (8,868,637)	$ (2,279,560)
FORECAST ENEC -DEMAND	$ 71,545,407	$ (1,630,091)
Less:		
Transmission Revenue (Demand)	$ 458,392,511	$ 2,172,358
Off-System Sales Revenue COGS (Demand)	$ -	$ -
Off-System Sales Margin (Demand)	$ 3,592,421	$ 963,605
FORECAST TOTAL COMPANY ENEC -DEMAND	$ (390,439,525)	$ (4,766,054)
WV DEMAND ALLOCATION FACTOR	0.407043	1.000000
WV RETAIL ENEC -DEMAND RELATED	$ (158,925,824)	$ (4,766,054)
Transmission Agreement Costs	$ 654,697,599	$ 70,143,228
Transmission Adjusted Allocation Factor	0.445847	1.000000
	$ 291,895,156	$ 70,143,228
TOTAL WV RETAIL ENEC - DEMAND RELATED	$ 132,969,332	$ 65,377,175
Total APCo and WPCo ENEC		$ 198,346,506

PROPOSED APPALACHIAN POWER COMPANY
EXPANDED NET ENERGY COST (ENEC) RATES
CASE NO. 22- XXXX -E-ENEC
EFFECTIVE DATE SEPTEMBER 1, 2022

CUSTOMER CLASS		ENEC ENERGY FACTOR C/KWH	ENEC DEMAND FACTOR $/KW
RS		6.110	
RS -TOD / RS-LM-TOD			
	ON-PEAK	6.110	
	OFF-PEAK	6.110	
SWS		5.925	
SGS	-SEC	5.331	
	-PRI	5.042	
SGS - LM-TOD			
	ON-PEAK	5.331	
	OFF-PEAK	5.331	
SS	-SEC	3.911	5.282
	-PRI	3.665	5.144
	-AF	5.457	
GS	-SEC	3.886	4.947
	-PRI	3.631	4.818
	-SUBTRAN	3.635	4.795
	-TRANS	3.504	4.694
	-AF	5.056	
GS:TOD			
ON-PEAK	-SEC	5.399	
OFF-PEAK	-SEC	5.399	
ON-PEAK	- PRI	4.928	
OFF-PEAK	-PRI	4.928	
LGS:TOD			
ON-PEAK	-SEC	3.886	4.947
OFF-PEAK	-SEC	3.886	4.947
ON-PEAK	- PRI	3.631	4.818
OFF-PEAK	-PRI	3.631	4.818
LCP	-SEC	4.037	6.205
	- PRI	3.807	6.196
	- SUBT	3.748	6.120
	- TRANS	3.558	5.924
IP	-SEC	4.037	6.205
	- PRI	3.807	6.196
	- SUBT	3.748	6.120
	- TRANS	3.558	5.924
OL		4.183	
SL		4.161	

PROPOSED APPALACHIAN POWER COMPANY
EXPANDED NET ENERGY COST (ENEC) RATES
CASE NO. 22- XXXX -E-ENEC
EFFECTIVE DATE SEPTEMBER 1, 2022

CUSTOMER CLASS		ENEC ENERGY FACTOR C/KWH	ENEC DEMAND FACTOR $/KW
SPECIAL CONTRACT B			
	138 KV SERVICE		
	CAPACITY CHARGE		6.101
	P1	3.610	
	P2	3.610	
	P2.5	3.610	
	P3	3.610	
	P4	3.610	
	46 KV SERVICE		
	P1	3.610	
	P2	3.610	
	P2.5	3.610	
	P3	3.610	
	P4	3.610	
SPECIAL CONTRACT C			
	P1	15.606	
	P2	15.606	
	P3	15.606	
	P4	15.606	
SPECIAL CONTRACT D			
	FIRM POWER	3.697	4.716
	ON-PEAK DEMAND		4.716
	SHOULD. PEAK DEM.		4.716
	OFF-PEAK DEMAND		4.716
	INTERR. ENERGY	3.697	
SPECIAL CONTRACT I			
	FIRM DEMAND	3.697	4.511
	ATOD DEMAND		4.511
SPECIAL CONTRACT J			
	BASE DEMAND CHARGE		2.804
	SPECIAL DEMAND CHARGE		2.804
	ENERGY CHARGE	3.777	
SPECIAL CONTRACT K		3.697	
	FIRM DEMAND		4.145
	ATOD DEMAND		4.145
FLOODWALL	ENEC Factor for floodwall accounts is the energy component of the appropriate general service tariff for which the customer would qualify.		

PROPOSED WHEELING POWER COMPANY
EXPANDED NET ENERGY COST (ENEC) RATES
CASE NO. 22- XXXX -E-ENEC
EFFECTIVE DATE SEPTEMBER 1, 2022

CUSTOMER CLASS		ENEC ENERGY FACTOR C/KWH	ENEC DEMAND FACTOR $/KW
RS		6.370	
RS -TOD / RS-LM-TOD			
	ON-PEAK	6.370	
	OFF-PEAK	6.370	
SWS		6.175	
SGS	-SEC	5.581	
	-PRI	5.292	
SGS - LM-TOD			
	ON-PEAK	5.581	
	OFF-PEAK	5.581	
SS	-SEC	4.161	5.282
	-PRI	3.915	5.144
	-AF	5.691	
GS	-SEC	4.136	4.947
	-PRI	3.881	4.818
	-SUBTRAN	3.880	4.795
	-TRANS	3.504	4.694
	-AF	5.290	
GS:TOD			
ON-PEAK	-SEC	5.649	
OFF-PEAK	-SEC	5.649	
ON-PEAK	- PRI	5.178	
OFF-PEAK	-PRI	5.178	
LGS:TOD			
ON-PEAK	-SEC	4.136	4.947
OFF-PEAK	-SEC	4.136	4.947
ON-PEAK	- PRI	3.881	4.818
OFF-PEAK	-PRI	3.881	4.818
LCP	-SEC	4.255	7.161
	- PRI	3.998	6.689
	- SUBT	3.954	6.578
	- TRANS	3.724	6.217
IP	-SEC	4.255	7.161
	- PRI	3.998	6.689
	- SUBT	3.954	6.578
	- TRANS	3.724	6.217
OL		4.183	
SL		4.161	

APPALACHIAN POWER COMPANY
WHEELING POWER COMPANY
DIRECT TESTIMONY
OF
JOHN J. SCALZO

DIRECT TESTIMONY OF JOHN J. SCALZO ON BEHALF OF APPALACHIAN POWER COMPANY AND WHEELING POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF WEST VIRGINIA IN CASE NO. 22-______________

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

A. My name is John J. Scalzo. I am Vice President – Regulatory Services and Finance for Appalachian Power Company ("APCo") and Wheeling Power Company ("WPCo"). My business address is 500 Lee Street, East, Charleston, West Virginia.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I graduated with a Bachelor of Science Degree in Accounting from The Ohio State University in 1992 and a Masters of Business Administration degree from Capital University in 2009. I have been an Ohio Certified Public Accountant since 1995. Between 1993 and 2002, I held various accounting positions in national and regional CPA firms. In 2002, I joined American Electric Power Service Corporation as a Staff Accountant. In 2004, I was promoted to Senior Staff Accountant, with my primary responsibility being the monthly accounting for several Generation business units within the system of American Electric Power Company, Inc. ("AEP"). In 2005, I accepted the position of Administrator of Corporate Accounting, where my responsibilities included Parent Company cash, benefits, and incentive accounting. In 2006, I was promoted to Manager of Corporate Accounting. In 2010, I was promoted to Director of Business Operations Support. In 2015, I accepted the position of Director of Regulatory Services for West Virginia. In 2018, I was promoted to Managing Director of Regulatory Services and Finance. In September 2020, I was promoted to my current position, Vice President – Regulatory Services and Finance.

Q. PLEASE BRIEFLY DESCRIBE YOUR JOB DUTIES AND RESPONSIBILITIES.

A. My duties include the supervision and direction of APCo's Regulatory Services and Business Operations Departments. This includes the responsibility for rate and regulatory matters affecting APCo's West Virginia and Virginia jurisdictions, WPCo, and Kingsport Power Company ("Kingsport") in Tennessee. APCo, WPCo, and Kingsport are operating subsidiaries of AEP. My responsibilities also include directing the Companies' resource allocation of capital and operation and maintenance programs. I direct the development of short-term and long-term financial plans and forecasts that are used by the Companies' management to monitor and maintain the Companies' financial health and condition.

Q. FOR WHOM ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of APCo and WPCo (together, the "Companies").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I filed testimony or testified in the Companies' previous base rate proceedings, Case Nos. 18-0646-E-42T and 14-1152-E-42T. Additionally, I have filed testimony or testified on behalf of the Companies in numerous ENEC proceedings and other proceedings.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address the Companies' need for further clarification regarding the Commission's directive to maximize the Companies' use of fossil-fuel generation.

Q. PLEASE EXPLAIN WHAT THE COMPANIES NEED CLARIFIED.

A. In the Companies' previous ENEC proceeding, Case No. 21-0339-E-ENEC, the Commission issued an order on September 2, 2021 wherein it "use[d] a capacity factor of 69 percent for the Companies' projected ENEC costs" and, resultingly, "reduce[d] the Companies' projected West Virginia jurisdictional ENEC costs by $66,681,445." The

Commission also directed the Companies to "focus[] on maximizing generation from [their] owned power plants."

On September 13, 2021, the Companies filed a Petition for Reconsideration or Clarification of that order, expressly requesting that the Commission clarify "how the Companies are to force the operation of their coal-fired generating units when they are not in the economic dispatch stack determined by PJM, the standard by which their decisions in this regard will be judged, and the recovery of the differential between the costs incurred when they self-select their units to run in lieu of purchasing lower-priced power from the PJM market."

On March 2, 2022, the Commission entered an order denying in part and granting in part the Companies' Petition for Reconsideration or Clarification and reopening the evidentiary phase of Case No. 21-0339-E-ENEC. In that order, the Commission again referenced the 69% capacity factor, stating: "If the Companies fail to achieve the level of capacity utilization established as a reasonable target by the Commission for their generating plants because of displacement of generation with purchased power, the necessity and prudence of [their] decisions leading to that result will be considered by the Commission when determining whether such future costs should be allowed for ratemaking purposes." However, in that order, the Commission did not provide the clarification that the Companies requested. In their testimony on reopening, certain of the Companies' witnesses reiterated that clarification is needed from the Commission as to whether the Companies should run their coal-fired plants out of merit to achieve a 69% capacity factor and whether the increased costs of doing so can be recovered solely from West Virginia jurisdictional customers.

As of this filing, the Commission has not issued any further orders in Case No. 21-0339-E-ENEC and, therefore, the Companies remain in need of the clarifications outlined above.

Q. IN LIGHT OF THE COMMISSION'S ORDERS, ARE THE COMPANIES UNSURE WHETHER THEY SHOULD CONTINUE TO FOLLOW THE ECONOMIC DISPATCH MODEL?

A. Yes, unfortunately the Companies are unsure what dispatch model they should be following going forward. As noted in their Petition for Reconsideration or Clarification, for decades the Companies have understood their obligation is to minimize costs for their customers and, accordingly, that they have flexibility to choose the most affordable generation source based on market conditions that results in the lowest cost to customers. Under the economic dispatch model, which the Companies have been following, PJM evaluates the cost of the various generation resources available to meet the needs of their members and calls upon those resources to operate based primarily on economics, starting with the least expensive resources and moving up progressively through more expensive resources.

The Commission's directive that the Companies should be targeting a 69% capacity factor at their coal-fired plants would appear at odds with the flexible, least-cost approach of economic dispatch. This is precisely why the Companies have asked for, and need, express clarification in an order from the Commission as to whether the Companies should abandon the economic dispatch model. The need for such clarification is compounded by the fact that the Companies operate across multiple jurisdictions and, given past precedents, or regulations, or both, the regulators in those jurisdictions almost certainly would not approve any unnecessary, increased costs arising from running the plants contrary to an economic dispatch approach.

Q. HAS THE LEVEL OF UNCERTAINTY INCREASED FOLLOWING THE COMMISSION'S SEPTEMBER 2, 2021 ORDER?

A. Yes. It has been discussed at length, both on reopening of Case No. 21-0339-E-ENEC and in the direct testimony submitted in this proceeding, that the fuel and energy markets are currently highly volatile. Coal pricing and supply from September 2021 to February 2022 impacted the Companies' coal-fired plants in several ways. Limited coal supply made it impossible to run at high capacity factors (and will continue to do so), and rising coal prices continue to make coal procurement challenging. At this point, the Companies are not only unsure of whether they should follow economic dispatch, but in light of volatile fuel markets, the Companies are unsure whether they should aim to procure coal at whatever the cost, and on terms no matter how unfavorable, simply to achieve a 69% capacity factor.

Q. ARE THE COMPANIES INFLUENCED BY ANY TYPE OF DECARBONIZATION GOAL?

A. Absolutely not. The notion that the Companies may be intentionally not running their coal-fired plants to achieve some type of decarbonization goal is simply not true. To summarize what has already been placed into evidence in this proceeding and in Case No. 21-0339-E-ENEC, the Companies' coal fired plants will run when (1) they have available fuel, (2) are not in a necessary outage (i.e., are "available"), and (3) when dispatched by PJM. Historical capacity factor data proves this. Unfortunately the current fuel markets have severely constrained coal supply, which is one of the factors that affects the ability of the coal-fired plants to run. As explained by Company witness Dial, the Companies are trying their best to obtain coal from both traditional and non-traditional sources at prices that make economic sense and that would allow the Companies' coal plants to be competitive in the PJM market on both a current and longer-term basis.

Q IN SUM, WHAT ARE THE COMPANIES ASKING FOR IN THIS CASE?

A. Apart from the ENEC rates requested in the Companies' Petition and described by other Company witnesses, the Companies must have clarification from the Commission regarding the "69% capacity factor" language of its prior September 2, 2021 and March 2, 2022 orders. Through PJM, the Companies have long employed economic dispatch to determine, at any given time, the most affordable generation, based on market conditions, that results in the lowest cost to customers. The Commission's March 2, 2022 Order seems to endorse this approach when it expresses its intent to have the Companies "follow a power supply policy to maximize their use of fossil-fuel generation that is cheaper than purchased power…." However, such an approach is inconsistent with the mandate to achieve a specific elevated capacity factor. Running the Companies' coal-fired units out of merit, in order to achieve a 69% (or higher) capacity factor, may very well result in increased costs to customers.

The Companies need clarification from the Commission that they are being ordered to "self-schedule" units to run when they otherwise would not be dispatched by PJM and, if so, under what parameters are the Companies to engage in such "self-scheduling." Furthermore, the Companies need assurance from the Commission that any cost premiums incurred as a result of self-scheduling versus dispatching on economic basis can be recovered fully from West Virginia ratepayers, as it is very unlikely that regulators in other jurisdictions will approve any such higher-than-necessary costs.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.