AMERICAN ELECTRIC POWER

BOUNDLESS ENERGY

American Electric Power
1051 E Cary Street, Suite 1100
Richmond, Virginia 23219
AEP.com

September 15, 2022

By Hand **PUBLIC VERSION**

Hon. Bernard J. Logan, Clerk
State Corporation Commission
Document Control Center
1300 East Main Street, First Floor
Richmond, Virginia 23219

Noelle J. Coates
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Re: Application of Appalachian Power Company To increase its fuel factor pursuant to § 56-249.6 of the Code of Virginia Case No. PUR-2022-00139

Dear Mr. Logan:

Enclosed for filing please find an original and four copies of the Public version of Appalachian Power Company's Application to increase its fuel factor pursuant to § 56-249.6 of the Code of Virginia.

The Company is also filing today under separate cover an original and 15 copies under seal of the Confidential version of this Application.

Sincerely,

Noelle J. Coates

Enclosures
cc: William H. Chambliss, Esq. (Letter only)
C. Meade Browder, Jr., Esq.

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

APPLICATION OF	)	
	)	
APPALACHIAN POWER COMPANY	)	CASE NO. PUR-2022-00139
	)	
To increase its fuel factor pursuant to	)	
§ 56-249.6 of the Code of Virginia	)	

APPLICATION

September 15, 2022

(PUBLIC VERSION)

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220920035

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

APPLICATION OF	)	
	)	
APPALACHIAN POWER COMPANY	)	CASE NO. PUR-2022-00139
	)	
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INDEX

Application

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION

APPLICATION OF	)	
	)	
APPALACHIAN POWER COMPANY	)	Case No. PUR-2022-00139
	)	
To increase its fuel factor pursuant to Va. Code § 56-249.6	)	
and to implement a rider pursuant to Va. Code § 56-236	)	

APPLICATION AND REQUEST TO IMPLEMENT RIDER

Pursuant to Section 56-249.6 of the Code of Virginia and 20 VAC 5-204-80, Appalachian Power Company ("Appalachian," "APCo," or the "Company") files this Application with the State Corporation Commission ("Commission") for approval of a revision of its fuel factor. Specifically, the Company proposes to increase the current fuel factor to 4.319 ¢/kWh effective November 2, 2022 through October 31, 2023 (the "fuel year"), which is an annual net increase in the revenue of approximately $279 million. To mitigate the impact of this request, the Company proposes to recover its deferred fuel balance as of October 31, 2022 over two fuel years. Finally, to ensure accuracy of the costs it recovers from its customers, the Company seeks the Commission's approval to implement a rider ("Rider DFCC") at a zero rate, to be updated and trued-up in the future, as an alternative to the recovery of the carrying costs on its deferred fuel balance through base rates.

In support of the Application, the Company states as follows:

1. Appalachian is a Virginia public service corporation serving approximately 530,000 customers in Virginia with its main office in Charleston, West Virginia and offices at Three James Center, 1051 East Cary Street, Suite 1100, Richmond, Virginia 23219. The Company sells electricity to retail customers in southwestern Virginia and southern West Virginia. Its Virginia jurisdictional retail rates and service are subject to regulation by the

Commission. The names and addresses of the Company's legal counsel are listed at the foot of this Application.

2. The following witnesses offer testimony in support of this Application:

- ***William K. Castle,*** Director of Regulatory Services-VA/TN for APCo. Mr. Castle supports a proposed, increased fuel factor of 4.319 ¢/kWh to become effective November 1, 2022. In support of this proposal, he provides the projected estimated under-recovered fuel balance of approximately $361.4 million as of October 31, 2022, the calculations for the new proposed fuel factor, and the projected fuel balance using the proposed fuel factor as of October 31, 2023. Mr. Castle provides the impact on customers of this request, and in an effort to moderate that impact, he proposes recovery of the deferred fuel balance over two years. Finally, Mr. Castle also discusses an alternative for the Commission's consideration with regard to the collection of carrying charges on unrecovered deferred fuel balances given the expected size of those balances as of December 31, 2022.

- ***Shelli A. Sloan,*** Director Financial Support and Special Projects (AEPSC). Ms. Sloan supports the total company fuel forecast of APCo. Ms. Sloan also provides the estimate of APCo's total company Net Energy Requirement of 31,744.5 GWh, and includable cost of $878.5 million, to Company witness Castle for use in determining APCo's proposed Virginia jurisdictional fuel factor for the period November 1, 2022 – October 31, 2023 ("Forecast Period").

- ***Kimberly K. Chilcote***, Coal Procurement Manager, Commercial Operations (AEPSC). Ms. Chilcote provides APCo's procurement strategy, provides an overview of the coal market in which the Company procures coal, describes the coal delivery forecast for the Forecast Period, and discusses APCo's portfolio of coal supply agreements.

- ***Clinton M. Stutler***, Natural Gas and Fuel Oil Manager (AEPSC). Mr. Stutler provides an overview of the natural gas market in which Appalachian procures gas; and discusses the Company's natural gas procurement strategy, including the Company's natural gas supply and transportation agreements.

- ***Ivanh D. Phung,*** Regulatory Case Manager (AEPSC). Mr. Phung explains the Company's participation in the PJM market and PJM's role in determining which generation units are dispatched. He also describes the energy market during the period of July 2021 through June 2022 ("Review Period"), as well as the Company's response to PJM market conditions.

- ***Michael J. Zwick,*** Vice President of Generating Assets for APCo. Mr. Zwick provides information about the Company's fossil-fueled generating fleet for the Review Period. He discusses Net Capacity Factor, Equivalent Availability

Factor, and the types of events that impact these generating units' performance data.

3. The Commission approved Appalachian's current fuel factor of 2.300 ¢/kWh in Case No. PUR-2021-00205, and it has been in effect since November 1, 2021.[1]

4. The testimony and exhibits demonstrate that a revision to the Company's existing fuel factor rate is necessary to provide the Company with the appropriate level of fuel cost recovery pursuant to Va. Code § 56-249.6 over the period beginning November 1, 2022 through October 31, 2023.

5. As Company witness Castle describes, the implementation of the proposed fuel factor will produce an estimated annual net increase of approximately $279 million.

6. The proposed fuel factor of 4.319 ¢/kWh is comprised of two components: an "in-period" component of 3.011 ¢/kWh, and a "prior-period" component of 1.308 ¢/kWh.

7. Mr. Castle explains that the in-period component is designed to recover the Virginia jurisdictional fuel cost projected to be incurred during the Forecast Period.

8. The prior-period component of the fuel factor fuel factor is a true-up component designed to recover the estimated $361,411,867 under-recovered deferred fuel balance as of October 31, 2022. The size of this deferred balance is substantial due to the sharp increase in commodity and market energy prices over the prior fuel year.

9. In order to mitigate some of the impact of the Company's request in this Application, the Company proposes to amortize and recover this balance over a two-year period, or $180,705,934 each year, over two fuel periods, from November 1, 2022, through October 31,

[1] Order Establishing 2021-2022 Fuel Factor, *Application of Appalachian Power Company To increase its fuel factor pursuant to § 56-249.6 of the Code of Virginia*, Case No. PUR-2021-00205, Doc. Con. Cen. No. 220320114 (March 15, 2022).

2024. As presented by Mr. Castle and proposed by the Company, this reduction of the prior period factor for the upcoming fuel year, from 2.615 ¢/kWh, to 1.308 ¢/kWh, moderates the total increase to a residential customer's bill from 26% to 15.8%.

10. The Company's projections for fuel costs continue to reflect an offset to projected fuel costs for 75% of the Company's projected off-system sales margins for the fuel year pursuant to Virginia Code § 56-249.6 D 1. In addition, the projections credit against fuel costs 100% of the financial transmission rights received through PJM auction revenue rights, and 100% of transmission line loss margins, rather than reflecting either of them in lower off-system sales margin credits at 75%.

11. The Company's fuel projections also reflect recovery of the energy value of the renewable purchase power agreements ("PPAs") that were approved for recovery in the Company's most recent Virginia Clean Economy Act proceeding.[2] The projections also include the "non-incremental costs" of certain wind PPAs, which were developed using the methodology adopted by the Commission in Case No. PUE-2015-00034.[3]

12. The effects of implementation of the proposed fuel factor on selected residential, commercial and industrial customers' typical monthly bills on and after November 1, 2022 are supported by Mr. Castle. For example, the proposed fuel factor would result in a Virginia

[2] Final Order, *Petition of Appalachian Power Company for approval of its 2021 RPS Plan under § 56.585.5 of the Code of Virginia and related requests*, Case No. PUR-2021-00206, Doc. Con. Cen. No. 220720045 (July 15, 2022).

[3] Final Order, *Petition of Appalachian Power Company, for approval of a rate adjustment clause, RPS-RAC, to recover the incremental costs of participation in the Virginia renewable energy portfolio standard program pursuant to Va. Code §§ 56-585.1 A 5 d and 56-585.2 E*, Case No. PUE-2015-00034, 2015 S.C.C. Ann. Rep. 317 (Nov. 16, 2015). Note that the Commonwealth's voluntary Renewable Portfolio Standard ("RPS") was replaced by a mandatory RPS established by the Virginia Clean Economy Act in 2020.

residential customer of APCo who uses 1,000 kWh/month experiencing a $20.17, or 15.8% increase in his monthly bill from $127.81 to $147.98.

13. Finally, the Company requests approval to implement Rider DFCC, which will help ensure that the rates its customers pay are accurate. Traditionally, the Company includes its deferred fuel balances as part of rate base in a base rate review, and, if rates are changed, an estimate of that balance, including the associated carrying charges, is included in rates going forward.

14. This is inherently difficult in general, and even more so due to the current volatility of the commodity markets and the magnitude of the expected fuel deferral as of December 31, 2022. As a result, base rates that are set in the Company's upcoming base rate case, to be filed in March 2023, could either under- or over-collect the true carrying charges of the actual fuel deferral balances. In lieu of the current ratemaking construct, the Company requests that the Commission approve Rider DFCC in this proceeding, and allow the Company to implement it with a zero rate. The Company proposes to begin deferring carrying charges on January 1, 2023, at the Company's approved cost of capital and capital structure. At a later date, the Company will return to the Commission for approval to begin to recover the actual carrying costs that it has incurred and deferred, subject to future true-up, until all such costs have been recovered. Rider DFCC will therefore be a mechanism to ensure that the Company's customers only pay the actual amount of the carrying costs. Mr. Castle explains this proposal in more detail in his testimony.

15. The Application and filing follow the applicable requirements contained in 20 VAC 5-204-10, 20 VAC 5-204-80, and 20 VAC 5-204-90. The Company has prepared an appendix to its Application incorporating the relevant information required by 20 VAC 5-204-80

and 20 VAC 5-204-90, including the actual information for each month for the most recent historical 12-month period of July 2021 through June 2022 and projections for the periods July 2022 through October 2022 and the rate year November 2022 through October 2023.

16. Under Rule 20 VAC 5-204-80, this filing necessarily contains confidential and/or proprietary information ("Confidential Information"). This Confidential Information is filed under seal and will be made available to respondent parties upon execution of an appropriate confidentiality agreement and entry of a protective ruling. Pursuant to Rate Case Rule 20 VAC 5-20-204-10 F and the Commission's Rules of Practice and Procedure Rules 5 VAC 5-20-110 and 5 VAC 5-20-170, Appalachian is filing a Motion for Protective Ruling and accompanying proposed Protective Ruling contemporaneously with this Application.

WHEREFORE the Company respectfully requests that the Commission issue an order that (1) authorizes implementation of a revised fuel factor of 4.319 ¢/kWh effective for service rendered November 1, 2022 through October 31, 2023; (2) authorizes the recovery of the deferred fuel balance over two fuel years; (3) approves a rider for the future recovery of the carrying charges on its deferred fuel balance; and (4) grants such other or further relief as may be necessary or appropriate to effect the intent of this Application.

Respectfully submitted,

APPALACHIAN POWER COMPANY

September 15, 2022

By ______________________
Counsel

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Counsel for Appalachian Power Company

Glossary of Terms

2015 APCo RPS-RAC Proceeding	Case No. PUE-2015-00034
2021 VCEA Proceeding	Case No. PUR-2021-00206
ADFIT	Accumulated Deferred Federal Income Tax
AEP	American Electric Power
AEPSC	American Electric Power Service Corporation
APCo or Company	Appalachian Power Company
Bcf	Billion cubic feet
Btu	British Thermal Units
CAPP	Central Appalachian
Ceredo	Ceredo Generating Plant
Code	Code of Virginia
Commission or SCC	The Virginia State Corporation Commission
Dresden	Dresden Generating Plant
EAF	Equivalent Availability Factor
EGTS	Eastern Gas Transmission and Storage
ETNG	East Tennessee Natural Gas
FT	Firm Transportation agreement
FTR	Financial Transmission Rights
GWh	Gigawatt hours
ICE	Intercontinental Exchange
ILB	Illinois Basin
IT	Interruptible Transportation agreement
KPCo	Kentucky Power Company
kW	Kilowatt
kWh	Kilowatt-hour
LMS-MA	Load Management Market Area Service Agreement
LNG	Liquified Natural Gas
LSE	Load Serving Entity
MDQ	Maximum Daily Quantity
MMBtu	Million British thermal units
MW	Megawatt
MWh	Megawatt-hour
NAPP	Northern Appalachian
NCF	Net Capacity Factor
NEC	Net energy cost
NYMEX	New York Mercantile Exchange
OSS	Off System Sales
OVEC	Ohio Valley Electric Corporation
PJM	PJM Interconnection LLC
PPA	Purchase Power Agreement
PRB	Powder River Basin
PSO	Public Service Company of Oklahoma
RFP	Request for Proposals
RPS	Renewable Energy Portfolio Standard
RTO	Regional Transmission Organization
SO_2	Sulfur Dioxide
Staff	State Corporation Commission Staff

SWEPCO	Southwestern Electric Power Company
VCEA	Virginia Clean Economy Act
WPCo	Wheeling Power Company

APCo Exhibit No. ___
Witness: WKC

**DIRECT TESTIMONY OF
WILLIAM K. CASTLE
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUR-2022-00139**

APCo Exhibit No. ___
Witness: WKC

SUMMARY OF DIRECT TESTIMONY OF
WILLIAM K. CASTLE

My direct testimony supports a proposed, increased fuel factor of 4.319¢/kWh to become effective November 1, 2022. In support of this proposal, I provide the estimated under-recovered fuel balance of approximately $361.4 million as of October 31, 2022, the calculations for the new proposed fuel factor, and the projected fuel balance using the proposed fuel factor as of October 31, 2023.

In an effort to moderate the impact to customers, I propose recovery of the deferred fuel balance over two years.

I discuss an alternative for the Commission's consideration with regard to the collection of carrying charges on unrecovered deferred fuel balances given the expected size of those balances as of December 31, 2022.

APCo Exhibit No. ___
Witness: WKC

DIRECT TESTIMONY OF
WILLIAM K. CASTLE
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUR-2022-00139

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

A. My name is William K. Castle. I am the Director of Regulatory Services-VA/TN for APCo, and my business address is 1051 East Cary St., Suite 1100, Richmond, Virginia 23219.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I earned a Bachelor of Science degree in Mechanical Engineering from Tulane University in 1988, and a Masters of Business Administration degree from the University of Texas – Austin in 1998. I hold the Chartered Financial Analyst (CFA) designation. I was an officer in the U.S. Navy from 1988-1996. I have worked in the utility industry since 1998, beginning with the Columbia Energy Group, Herndon, Virginia, where I held positions in financial planning and corporate finance. Subsequent to the acquisition of Columbia Energy Group by Merrillville, Indiana-based NiSource in 2000, I performed financial planning and analysis functions. In 2004 I was employed by AEPSC in the Corporate Planning and Budgeting Department, including Resource Planning. In 2014, I accepted my current position.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. I regularly provide testimony on behalf of APCo before the State Corporation Commission, and previously testified before regulatory commissions in Ohio, Oklahoma, Indiana, West Virginia, Arkansas, and Tennessee.

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

A. The purpose of my testimony is to support the Company's proposed fuel factor to be effective November 1, 2022. In that regard, I am sponsoring the following exhibits:

- APCo Exhibit No. ___ (WKC) Schedule 1 - APCo's actual total company fuel cost by month for the period July 2021 through June 2022 and the booking estimate of total company fuel cost for the month of July 2022;
- APCo Exhibit No. ___ (WKC) Schedule 2 - APCo's Virginia jurisdictional fuel cost recovery position projected as of October 31, 2022;
- APCo Exhibit No. ___ (WKC) Schedule 3 - Development of the Virginia jurisdictional fuel factor to be effective November 1, 2022;
- APCo Exhibit No. ___ (WKC) Schedule 4 - The projected Virginia jurisdictional fuel cost recovery position as of October 31, 2023, assuming implementation of the proposed fuel factor for service rendered beginning November 1, 2022;
- APCo Exhibit No. ___ (WKC) Schedule 5 - Revision of Virginia SCC Tariff No. 26 Schedule F.F.R. (Fuel Factor Rider) to incorporate the Company's proposed fuel factor effective November 1, 2022;
- APCo Exhibit No. ___ (WKC) Schedule 6 - Schedules summarizing the estimated total revenue change associated with the proposed fuel factor change broken down into in-period and true-up components; and
- APCo Exhibit No. ___ (WKC) Schedule 7 - A sample billing analysis indicating the effects of the change in the proposed fuel factor on typical customers' monthly bills.

Q. WHAT IS THE COMPANY PROPOSING IN THIS PROCEEDING?

A. The Company is proposing that its current fuel factor of 2.300¢/kWh, which was placed in effect November 1, 2021, be increased to 4.319¢/kWh as shown in APCo Exhibit No. ___ (WKC) Schedule 3. The Company requests that its proposed fuel factor, which mitigates the increase by spreading the unrecovered deferred fuel balance over an initial two-year period, become effective November 1, 2022. In addition, I propose deferring carrying charges on unrecovered fuel balances, for collection through a future rider, as an alternative to recovery through base rates.

I. <u>ACTUAL FUEL COST</u>

Q. HAVE YOU DEVELOPED A SCHEDULE THAT PRESENTS THE ACTUAL MONTHLY FUEL COST FOR THE PERIOD JULY 2021 THROUGH JUNE 2022?

A. Yes. APCo Exhibit No. __ (WKC) Schedule 1 displays the actual total Company fuel cost by month for the period July 2021 through June 2022 and for July 2022 based on the Company's booking estimate.

Q. WHY DOES THE ACTUAL FUEL COST DATA PRESENTATION START WITH THE JULY 2021 VALUES?

A. In the Company's most recent fuel filing the most current actual fuel cost data presented by the Company was for June 2021. In this proceeding, the actual fuel cost data presentation begins with July 2021 in order to provide an uninterrupted series of actual cost data.

II. <u>PROJECTED FUEL COST RECOVERY POSITION AS OF OCT. 31, 2022, AND TWO YEAR DEFERRED FUEL BALANCE RECOVERY</u>

Q. WHAT IS THE COMPANY'S VIRGINIA JURISDICTIONAL FUEL COST RECOVERY POSITION EXPECTED TO BE AS OF OCTOBER 31, 2022?

A. APCo Exhibit No. __ (WKC) Schedule 2 summarizes the Company's cumulative Virginia jurisdictional fuel cost recovery position, beginning with the June 30, 2021 actual cumulative fuel cost recovery balance; continuing on a monthly basis with actual values from July 2021 through June 2022 and the booking estimate for July 2022; and from August 2022 through October 2022 on a projected basis (using projected monthly fuel cost and energy sales data sponsored by Company witness Sloan in this proceeding). As can be observed from APCo Exhibit No. __ (WKC) Schedule 2, APCo is expected to have a Virginia jurisdictional cumulative fuel cost under-recovery of approximately $361.4 million as of October 31, 2022, which the Company is proposing to recover over a two-year period.

Q. WHY IS THE COMPANY PROPOSING TO RECOVER THE ACCUMULATED FUEL DEFERRAL BALANCE OVER TWO YEARS?

A. The cumulative Virginia jurisdictional fuel cost recovery position calculated in this proceeding is significant, reflecting the increase in commodity and market energy prices over the prior fuel year. The Company is proposing to recover the accumulated deferred fuel balance over two years in order to moderate the impact to customers of the large increase to the fuel factor over the upcoming period.

If approved, the Company will amortize the October 31, 2022 projected fuel deferral balance of $361.4 million over two fuel periods, from November 1, 2022, through October 31, 2024 (24 months). This would result in a reduction to the prior period factor for the upcoming fuel year, from 2.615¢/kWh, to 1.308¢/kWh, reducing the total impact to a residential customer's bill from 26% to 15.8%.

III. PROPOSED FUEL FACTOR

Q. WHAT IS THE COMPANY'S REQUEST REGARDING THE LEVEL OF THE FUEL FACTOR AND THE EFFECTIVE DATE OF CHANGE IN THE CURRENT FACTOR?

A. As previously stated, the Company is presenting evidence that supports a fuel factor of

4.319¢/kWh, comprised of an in-period component of 3.011¢/kWh and a prior-period component of 1.308¢/kWh, and requests that the Commission approve this proposed factor to become effective for service rendered on and after November 1, 2022.

Q. PLEASE BRIEFLY DESCRIBE HOW THE IN-PERIOD COMPONENT PROPOSED FUEL FACTOR WAS DEVELOPED.

A. APCo Exhibit No. __ (WKC) Schedule 3 demonstrates the development of the two components constituting the proposed fuel factor.

The first, or in-period, component (APCo Exhibit No. __ (WKC) Schedule 3, Line 3) of the proposed fuel factor is designed to recover the Virginia jurisdictional fuel cost projected to be experienced during the period November 1, 2022 through October 31, 2023. To obtain the in-period component, the projected fuel cost allocated to the Virginia jurisdiction (APCo Exhibit No. __ (WKC) Schedule 3, Line 1) of $416,140,161, which includes the non-incremental costs associated with APCo's Beech Ridge and Grand Ridge wind contracts as approved in the 2015 APCo RPS-RAC Proceeding, and the energy components of the Company's other wind and solar resources, whether owned or contracted, as defined and approved in the 2021 VCEA Proceeding, a credit for 75% of projected OSS margins, PJM LSE transmission losses, PJM congestion charges, 100% of incremental transmission line loss margins, and FTR revenues, was divided by the projected Virginia jurisdictional energy sales for the 12 month period of 13,819,411,000 kWh (APCo Exhibit No. __ (WKC) Schedule 3, Line 2). The resulting in-period fuel cost recovery component is 3.011¢/kWh.

Q. PLEASE BRIEFLY DESCRIBE HOW THE PRIOR-PERIOD COMPONENT

PROPOSED FUEL FACTOR WAS DEVELOPED.

A. The second component (APCo Exhibit No. __ (WKC) Schedule 3, Line 7) of the proposed fuel factor is a true-up component designed to recover the estimated $361,411,867 under-recovered deferred fuel balance as of October 31, 2022 over a two-year period (APCo Exhibit No. __ (WKC) Schedule 2), or $180,705,934 each year. This amount was divided by the projected Virginia jurisdictional energy sales for the period November 1, 2022 - October 31, 2023 to obtain the prior period under-recovery component of 1.308¢/kWh.

The combination of these two components (APCo Exhibit No. __ (WKC) Schedule 3, Line 8) produces the proposed fuel factor of 4.319¢/kWh.

IV. <u>PROJECTED FUEL COST RECOVERY POSITION AS OF OCTOBER 31, 2023</u>

Q. **HAVE YOU PREPARED A SCHEDULE SUMMARIZING THE PROJECTED FUEL COST RECOVERY POSITION AS OF OCTOBER 31, 2023?**

A. Yes, APCo Exhibit No. __ (WKC) Schedule 4 summarizes the projected Virginia jurisdictional fuel cost recovery position on a monthly and cumulative basis through October 31, 2023, based upon projected fuel cost and energy sales data sponsored by Company witness Sloan in this proceeding, and using the proposed fuel factor of 4.319¢/kWh developed in APCo Exhibit No. __ (WKC) Schedule 3. APCo Exhibit No. ___ (WKC) Schedule 4 shows that the use of this proposed factor is expected to result in a projected fuel cost under-recovery position of $180,691,664 as of October 31, 2023.

V. <u>REVISED TARIFF</u>

Q. **PLEASE DESCRIBE HOW THE PROPOSED FUEL FACTOR WOULD BE**

INCORPORATED IN THE COMPANY'S TARIFF.

A. The proposed fuel factor would be shown on tariff Sheet No. 52 entitled "Rider F.F.R." APCo Exhibit No. __ (WKC) Schedule 5 illustrates how the proposed fuel factor would be incorporated in the tariff schedule in the Company's Virginia SCC Tariff No. 26, to be effective with service rendered on and after November 1, 2022.

VI. <u>REVENUE AND BILL IMPACTS</u>

Q. WHAT IS THE NET REVENUE IMPACT OF IMPLEMENTING THE COMPANY'S PROPOSED FUEL FACTOR?

A. APCo Exhibit No. __ (WKC) Schedule 6 shows the components of the Virginia jurisdictional 12-month net revenue impact using the Company's proposed fuel factor, which produces an estimated annual revenue net increase of $279,013,908.

Q. WHAT IS THE IMPACT OF IMPLEMENTATION OF THE PROPOSED FUEL FACTOR ON THE MONTHLY BILLS OF THE COMPANY'S VIRGINIA RETAIL CUSTOMERS?

A. APCo Exhibit No. ___ (WKC) Schedule 7 shows the effects of implementation of the proposed fuel factor on selected residential, commercial and industrial customers' typical monthly bills on and after November 1, 2022. For example, billing under the proposed fuel factor, as contained in APCo Exhibit No. __ (WKC) Schedule 5, would result in a Virginia residential customer of APCo who uses 1,000 kWh/month experiencing a $20.17, or 15.8% increase in his monthly bill from $127.81 to $147.98.

VI. <u>RECOVERY OF CARRYING CHARGES ON DEFERRED FUEL BALANCES</u>

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO DEFER CARRYING

CHARGES ON UNRECOVERED FUEL BALANCES.

A. The Company expects to have an uncollected Virginia jurisdictional fuel balance of $338 million at the end of 2022. Currently, the deferred fuel balance, net of Accumulated Deferred Federal Income Tax (ADFIT), is included in rate base in triennial proceedings. There is inherent inaccuracy in attempting to gauge the actual level of uncollected fuel balances that will be representative of the entire next Triennial Period under this method, which could lead to setting base rates that ultimately either under or over collect the true carrying charges of the actual fuel deferral balances net of ADFIT. This is especially true considering the magnitude of the expected fuel deferral as of December 31, 2022. In lieu of the traditional ratemaking construct, the Company proposes to begin deferring carrying charges January 1, 2023, at the Company's approved cost of capital and capital structure, for collection through a rider (Rider DFCC), subject to true-up.

Q. HOW WOULD THIS PROPOSED RIDER DFCC IMPACT THE UPCOMING TRIENNIAL FILING IN MARCH 2023?

A. If approved, the Company would, as is standard practice, include deferred fuel balances net of ADFIT in rate base for the earnings test and going forward revenue requirement in its base case filing, to be made by the end of March 2023, as a Commission decision on the Company's proposal in this case is not due until approximately the same time. If the Commission approves the Company's request to implement Rider DFCC in this proceeding, the deferred fuel balance net of ADFIT would then be removed from the going forward rate base and revenue requirement during the course of the triennial proceeding. The Company will provide in its 2023 triennial filing the base rate revenue requirement impact if the Commission were to approve the Company's request.

Q. HOW WOULD THE COMPANY PROPOSAL IMPACT THE 2023-2025 EARNINGS TEST?

A. If the Commission approves the Company's proposal, the Company would not include deferred fuel balance net of ADFIT in the earnings test for 2023, 2024 and 2025.

Q. WHEN THE DOES THE COMPANY PROPOSE TO IMPLEMENT THE RIDER?

A. If the Commission approves Rider DFCC in this proceeding, the Company proposes to implement it with a zero rate, and will provide the Commission with an estimate of fuel balances through the end of calendar year 2023, beginning with an actual 2022 year-end balance. Thereafter, the Company will seek the Commission's permission to implement rates through the Rider as soon as practical. Rider DFCC would be subject to true-up, reflecting actual balances on an annual basis until such time that it is no longer necessary.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

APCo Exhibit No. ___
Witness: WKC
Schedule 1

220920035

APPALACHIAN POWER COMPANY
TOTAL COMPANY FUEL COST- ACTUAL
JULY 2021 - JUNE 2022

Line No.		(A) July 2021	(A) August 2021	(A) September 2021	(A) October 2021	(A) November 2021	(A) December 2021	(A) January 2022	(A) February 2022	(A) March 2022	(A) April 2022	(A) May 2022	(A) June 2022
	Fuel-related Expense ($)												
1	Generation Expense*	60,871,491	63,190,734	38,358,931	14,224,284	23,480,358	56,188,399	56,644,753	44,059,851	25,079,007	23,821,216	33,478,960	49,630,796
	Plus:												
2	Purchases (total cost)	10,389,456	13,389,244	32,032,734	93,352,087	111,931,147	27,035,208	50,607,741	48,156,000	71,614,571	89,250,551	111,810,546	104,962,314
3	Purchase Power RPS Facilities	999,616	981,001	2,320,265	2,107,152	2,728,259	4,272,995	5,504,737	4,848,125	5,008,620	4,970,486	3,861,924	2,966,133
4	Purchase Power Non-RPS Facilities	590,427	646,934	1,080,703	1,244,546	1,588,417	2,915,577	5,535,960	5,249,610	5,394,800	4,983,230	3,583,960	2,782,650
	Less:												
5	Energy Generated for Off-System Sales (A/C 151)	14,195,110	17,026,712	6,191,455	2,253,694	3,551,877	13,604,438	9,920,868	3,408,299	5,537,565	7,160,839	13,982,370	9,478,919
6	Total Net Energy Cost	58,655,880	61,181,202	67,601,179	108,674,375	136,176,303	76,807,741	108,372,324	98,905,287	101,559,433	115,864,644	138,753,021	150,862,974
7	Purchase Power RPS Facilities(Amount Not Recovered in Fuel)	(699,740)	(655,991)	(1,219,907)	(1,849,188)	(2,355,517)	(2,420,004)	(2,590,256)	(2,280,597)	(2,343,638)	(2,339,272)	(1,812,423)	(1,390,677)
8	Purchase Power Non-RPS Facilities (Amount Not Recovered in Fuel)	(1,064,948)	(1,064,144)	(1,795,776)	(2,787,277)	(3,596,290)	(3,717,129)	(2,232,653)	(2,117,168)	(2,175,723)	(2,009,737)	(1,445,411)	(1,122,243)
9	Coal Liquidations Margins	0	0	0	0	0	0	0	0	0	0	0	0
10	75% of Off-System Sales Margin Credit	(1,166,903)	(2,344,831)	(501,104)	929,307	(105,946)	(2,908,479)	(91,840)	(484,910)	(290,913)	(467,427)	(534,143)	(289,783)
11	PJM LSE Transmission Losses	1,682,408	2,010,173	1,089,668	757,013	1,652,520	1,650,599	3,321,770	504,101	53,053	1,442,572	700,557	1,068,275
12	100% of Incremental Transmission Line Loss Margins	(720,015)	(812,531)	(129,038)	(2,849,438)	(653,475)	(616,753)	519,331	424,668	235,453	(295,024)	(214,978)	(537,058)
13	FTR Revenues	(1,233,747)	(1,179,631)	(933,524)	(2,536,798)	(9,631,941)	(3,729,207)	(17,578,617)	(5,370,727)	(2,438,464)	(2,882,711)	(4,806,000)	(5,112,021)
14	PJM Implicit Congestion Charges	874,815	1,373,081	1,174,631	5,401,169	12,283,689	2,703,449	16,004,504	5,356,362	4,621,991	6,543,588	2,389,816	7,433,505
15	Includable Cost	58,092,436	60,227,463	68,301,811	110,375,628	139,721,150	73,907,350	110,547,471	99,334,780	103,740,554	120,205,642	136,288,273	153,425,893
	Energy (MWH)												
16	Fossil Generation	2,888,440	2,902,271	1,614,473	449,304	602,822	2,311,708	2,526,412	1,636,432	751,467	648,702	758,256	1,128,249
17	Hydro Generation	16,751	17,042	21,386	17,527	23,469	15,510	38,458	53,093	65,917	58,390	59,593	24,361
18	Total Generation	2,905,191	2,919,313	1,635,860	466,831	626,291	2,327,218	2,564,870	1,689,524	817,384	707,092	817,849	1,152,611
	Plus:												
19	Purchases	345,381	378,765	747,892	1,690,071	1,899,193	722,207	858,803	1,024,595	1,647,676	1,471,854	1,493,128	1,359,060
20	Purchases - RPS Facilities	27,407	28,055	67,364	60,189	74,158	85,463	81,534	92,365	90,879	86,952	73,455	47,932
21	Purchases - Non-RPS Facilities	18,528	18,600	34,798	41,974	52,400	58,858	38,667	50,048	58,051	47,222	33,063	29,374
22	Purchases - Solar	0	0	0	0	5,663	3,374	2,430	2,852	4,067	4,511	4,851	5,003
	Less:												
23	Energy Purchases and Generated for Off-System Sales	614,648	616,812	190,235	31,811	56,788	544,936	168,444	66,054	119,653	106,033	155,156	107,831
24	Total Net Energy Requirement	2,681,858	2,727,921	2,295,680	2,227,253	2,600,919	2,652,184	3,377,860	2,793,331	2,498,403	2,211,598	2,267,190	2,486,148
25	Net Energy Cost (Mills/KWH)	21.66	22.08	29.75	49.56	53.72	27.87	32.73	35.56	41.52	54.35	60.11	61.71

(*) Excludes demurrage expense
(A) Actual
(E) Booking Estimate

APCo Exhibit No. __
Witness: WKC
Schedule 2

APPALACHIAN POWER COMPANY
VIRGINIA JURISDICTION
PROJECTED FUEL COST RECOVERY POSITION
AS OF OCTOBER 2022

	Virginia Jurisdictional Energy Sales	Fuel Factor Recovery (a)(c)	Total Company Fuel Cost (b)	Energy Allocation Factor (d)	Virginia Retail Fuel Cost Col. (3) x Col. (4)	Monthly NEC Over (Under) Recovery Col. (2)- (5)	Cumulative Fuel Cost Over(Under) Recovery Position
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	(KWH)	($)	($)		($)	($)	($)
Balance at June 2021							(24,706,135)
7/21 - Adjust March 2019-May 2021 VA Deferred Fuel for Demurrage Charges						306,203	(24,399,932)
(A) July	1,174,642,666	23,481,107	58,092,436	0.469439	27,270,855	(3,789,748)	(28,189,680)
(A) August	1,252,622,389	25,039,922	60,227,463	0.477371	28,750,844	(3,710,922)	(31,900,602)
(A) September	1,008,080,618	20,151,532	68,301,811	0.470820	32,157,858	(12,006,326)	(43,906,928)
(A) October	1,032,879,267	20,647,257	110,375,628	0.466388	51,477,868	(30,830,611)	(74,737,539)
(A) November	1,178,342,324	27,101,873	139,721,150	0.473445	66,150,280	(39,048,407)	(113,785,946)
Jun - Nov 2021 Adj Non-Incremental Wind Costs						(5,895,209)	(119,681,155)
(A) December	1,190,989,359	27,392,755	73,907,350	0.480199	35,490,236	(8,097,481)	(127,778,636)
Jan - Dec 2021 Adj Non-Incremental Wind Costs						(1,052,300)	(128,830,936)
(A) January 2022	1,498,549,101	34,465,501 (c)	105,564,363	0.478654	50,528,805	(16,063,304)	(144,894,240)
(A) February	1,238,594,884	28,487,312	96,562,110	0.474162	45,786,083	(17,298,771)	(162,193,011)
Mar Adjustment - Yearly Virginia Deferred						(615,491)	(162,808,502)
(A) March	1,114,389,435	25,512,922	100,282,514	0.466773	46,809,170	(21,296,248)	(184,104,750)
(A) April	989,423,379	22,756,987	116,553,377	0.472034	55,017,157	(32,260,170)	(216,364,920)
(A) May	1,080,388,214	24,858,971	134,258,367	0.478896	64,295,795	(39,436,824)	(255,801,744)
06/21 - 2022 Jan-May Non-Incr Wind Adj						(1,902,290)	(257,704,034)
(A) June	1,098,177,279	25,270,667	151,879,802	0.476171	72,320,757	(47,050,090)	(304,754,124)
(E) July	1,230,620,000	27,504,417	87,972,649	0.476171	41,890,024	(14,385,607)	(319,139,731)
(P) August	1,147,293,000	22,934,387	81,154,029	0.473696 (d)	38,442,339	(15,507,952)	(334,647,683)
(P) September	1,013,810,000	20,266,062	65,407,868	0.473696 (d)	30,983,445	(10,717,383)	(345,365,066)
(P) October	1,007,708,000	20,144,083	76,401,076	0.473696 (d)	36,190,884	(16,046,801)	(361,411,867)

(a) July 2021 - October 2021: Col. 1 x $0.01999/kWh
(b) Excludes demurrage expense.
(c) Monthly recovery amounts changed to reflect actual monthly revenue $ instead of kWh Jan 2022
(d) Average Virginia energy allocation factor (July '21 - June '22)
(A) Actual; (E) Booking Estimate; (P) Projected.

APCo Exhibit No. __
Witness: WKC
Schedule 2

APCo Exhibit No. ___
Witness: WKC
Schedule 3

APPALACHIAN POWER COMPANY
VIRGINIA JURISDICTION
DERIVATION OF FULL FUEL FACTOR

Line No.					¢/kWh
1	Projected Virginia Jurisdictional Fuel Cost November 2022 - October 2023	$	416,140,161	(A)	
2	Projected Virginia Jurisdictional Energy Sales, November 2022 - October 2023	÷	13,819,411,000	KWH (B)	
3	In-period Fuel Cost Recovery Component				3.011
4	Projected Fuel Cost Underrecovery as of October 31, 2022	$	361,411,867	(C)	
		÷	2		
5	1/2 Projected Deferral Balance (2 Yr Mitigation)		180,705,934		
6	Projected Virginia Jurisdictional Energy Sales, November 2022 - October 2023	÷	13,819,411,000	KWH (B)	
7	Prior-period Fuel Cost Underrecovery Component				1.308
8	Total Fuel Factor				4.319

(A) Per APCo Exhibit No._ (WKC) Schedule 4, Column 5.

(B) Per APCo Exhibit No.____(WKC) Schedule 4, Column 1.

(C) Per APCo Exhibit No.____(WKC) Schedule 2, Column 7.

APCo Exhibit No. _
Witness: WKC
Schedule 4

APPALACHIAN POWER COMPANY
VIRGINIA JURISDICTION
PROJECTED FUEL COST RECOVERY POSITION
AS OF OCTOBER 31, 2023

	Projected Virginia Jurisdictional Energy Sales (1) (KWH)	Projected Fuel Factor Recovery (a) (2) ($)	Projected Total Company Fuel Cost (3) ($)	Projected Monthly Energy Allocation Factor (b) (4)	Projected Virginia Retail Fuel Cost Col. 3 x Col. 4 (5) ($)	Projected Monthly Fuel Cost Over (Under) Recovery Col. 2 - Col. 5 (6) ($)	Projected Cumulative Fuel Cost Over(Under) Position (7) ($)
Cum. Over (Under) Recovery as of October 31, 2022							(361,411,867)
November	1,198,125,000	15,671,475	87,337,695	0.473696	41,371,517	(25,700,042)	(387,111,909)
December	1,216,203,000	15,907,935	82,863,813	0.473696	39,252,257	(23,344,322)	(410,456,231)
January 2023	1,490,605,000	19,497,113	82,380,022	0.473696	39,023,087	(19,525,974)	(429,982,205)
February	1,245,072,000	16,285,542	76,262,169	0.473696	36,125,084	(19,839,542)	(449,821,747)
March	1,176,246,000	15,385,298	69,105,069	0.473696	32,734,795	(17,349,497)	(467,171,244)
April	980,036,000	12,818,871	62,911,424	0.473696	29,800,890	(16,982,019)	(484,153,263)
May	1,050,229,000	13,736,995	68,562,023	0.473696	32,477,556	(18,740,561)	(502,893,824)
June	1,066,210,000	13,946,027	66,426,713	0.473696	31,466,068	(17,520,041)	(520,413,865)
July	1,219,317,000	15,948,666	79,675,577	0.473696	37,742,002	(21,793,336)	(542,207,201)
August	1,144,019,000	14,963,769	75,449,946	0.473696	35,740,338	(20,776,569)	(562,983,770)
September	1,007,319,000	13,175,733	63,841,144	0.473696	30,241,295	(17,065,562)	(580,049,332)
October	1,026,030,000	13,420,472	63,680,656	0.473696	30,165,272	(16,744,800)	(596,794,132)
	13,819,411,000	180,757,896	878,496,251		416,140,161	(235,382,265)	

(a) November 2022 through October 2023: Col. 1 x $ 0.01308 /kWh.
(b) Average Virginia energy allocation factor (July '21 - June '22)

APCo Exhibit No. _
Witness: WKC
Schedule 4

220920035

APPALACHIAN POWER COMPANY

~~First~~ Second Revision of Sheet No. 52

VA. S.C.C. TARIFF NO. 26

RIDER F.F.R.
(Fuel Factor Rider)

AVAILABILITY OF SERVICE

A Fuel Factor Rider will be applied to all standard customer service rendered under the Applicable Schedules or special contracts. The Fuel Factor Rider shall be calculated by multiplying the customer's kWh by 4.319~~2.300~~¢ per kilowatt-hour.

The Fuel Factor Rider shall remain in effect until such time as modified by the Commission.

Issued:
Pursuant to Procedural Order
Dated:
Case No. PUR-2022~~1~~-00139~~205~~

Effective: November 1, 2022~~1~~

APPALACHIAN POWER COMPANY

**Second Revision of
Sheet No. 52**

VA. S.C.C. TARIFF NO. 26

**RIDER F.F.R.
(Fuel Factor Rider)**

AVAILABILITY OF SERVICE

A Fuel Factor Rider will be applied to all standard customer service rendered under the Applicable Schedules or special contracts. The Fuel Factor Rider shall be calculated by multiplying the customer's kWh by 4.319 ¢ per kilowatt-hour.

The Fuel Factor Rider shall remain in effect until such time as modified by the Commission.

**Issued:
Pursuant to Procedural Order
Dated:
Case No. PUR-2022-00139**

Effective: November 1, 2022

APCo Exhibit No. ____
Witness: WKC
Schedule 6

APPALACHIAN POWER COMPANY
VIRGINIA JURISDICTION
ESTIMATED REVENUE INCREASE
ASSOCIATED WITH THE PROPOSED FUEL FACTOR
FOR THE PERIOD NOVEMBER 2022 - OCTOBER 2023

Increase attributable to change in in-period Component:							
Proposed	$	0.03011	/KWH				
Current	-	0.02021					
Increase		0.00990	/KWH				
Projected energy sales	×	13,819,411,000	KWH			$	136,812,169
Change in Prior-Period True-up Component:							
Increase attributable to implementation of proposed 2 year mitigated prior-period underrecovery collection component:							
Proposed component	$	0.01308	/KWH				
Projected energy sales	×	13,819,411,000	KWH	$	180,757,896		
Change attributable to removal of current prior-period undererrecovery collection component:							
Current component	$	0.00279	/KWH				
Projected energy sales	×	13,819,411,000	KWH		38,556,157		
Subtotal- Increase attributable to change in prior-period component						$	142,201,739
Total estimated 12-month revenue increase/(decrease) associated with the proposed fuel factor change						$	279,013,908

220920035

APPALACHIAN POWER COMPANY
VIRGINIA JURISDICTION
SELECTED TYPICAL MONTHLY BILLS

	Tariff Schedule	Energy / Demand Consumption	Bill Amount (a) Under Current Rates VA SCC Tariff No. 26 Effective 9/1/2022	Bill Amount (a) Under Proposed Fuel Factor VA SCC Tariff No. 26 Effective 11/1/2022	Dollar Increase	Percent Increase
			$	$	$	%
RS		100 kWh	19.46	21.48	2.02	10.4%
RS		250 kWh	37.55	42.59	5.04	13.4%
RS		500 kWh	67.65	77.74	10.09	14.9%
RS		750 kWh	97.72	112.84	15.12	15.5%
RS		1,000 kWh	127.81	147.98	20.17	15.8%
RS		1,500 kWh	188.04	218.30	30.26	16.1%
RS		2,000 kWh	248.19	288.53	40.34	16.3%
RS		3,000 kWh	368.57	429.08	60.51	16.4%
RS		5,000 kWh	609.34	710.19	100.85	16.6%
RS		7,500 kWh	910.34	1,061.62	151.28	16.6%
SWS		1,500 kWh	201.25	231.54	30.29	15.1%
SWS		3,000 kWh	393.56	454.13	60.57	15.4%
SWS		5,000 kWh	650.00	750.95	100.95	15.5%
SWS		10,000 kWh	1,291.10	1,493.00	201.90	15.6%
SWS		30,000 kWh	3,855.53	4,461.23	605.70	15.7%
SWS		50,000 kWh	6,419.95	7,429.45	1,009.50	15.7%
SGS		375 kWh	49.47	57.04	7.57	15.3%
SGS		1,000 kWh	116.66	136.85	20.19	17.3%
SGS		2,000 kWh	224.21	264.59	40.38	18.0%
SGS		4,000 kWh	439.30	520.06	80.76	18.4%
MGS	Secondary	30 kW / 6,000 kWH	719.58	840.72	121.14	16.8%
	Secondary	50 kW / 12,500 kWH	1,426.98	1,679.36	252.38	17.7%
	Secondary	150 kW / 60,000 kWH	6,375.98	7,587.38	1,211.40	19.0%
MGS	Primary	250 kW / 50,000 kWH	5,516.57	6,526.07	1,009.50	18.3%
	Primary	500 kW / 200,000 kWH	19,754.62	23,792.62	4,038.00	20.4%
GS	Secondary	40 kW / 10,000 kWH	1,150.17	1,352.07	201.90	17.6%
	Secondary	75 kW / 30,000 kWH	2,811.59	3,417.29	605.70	21.5%
	Secondary	500 kW / 150,000 kWH	16,117.42	19,145.92	3,028.50	18.8%
GS	Primary	1,000 kW / 200,000 kWH	22,071.07	26,109.07	4,038.00	18.3%
	Primary	1,000 kW / 400,000 kWH	34,897.74	42,973.74	8,076.00	23.1%
LPS	Secondary	1,000 kW / 450,000 kWH	41,008.72	50,094.22	9,085.50	22.2%
	Secondary	2,000 kW / 1,000,000 kWH	85,088.93	105,278.93	20,190.00	23.7%
	Secondary	3,000 kW / 2,000,000 kWH	143,855.24	184,235.24	40,380.00	28.1%
LPS	Primary	3,500 kW / 2,000,000 kWH	148,596.84	188,976.84	40,380.00	27.2%
	Primary	5,000 kW / 3,000,000 kWH	216,877.85	277,447.85	60,570.00	27.9%
LPS	Subtransmission	10,000 kW / 5,000,000 kWH	367,167.95	468,117.95	100,950.00	27.5%
	Subtransmission	20,000 kW / 13,000,000 kWH	832,516.29	1,094,986.29	262,470.00	31.5%
LPS	Transmission	15,000 kW / 9,000,000 kWH	593,684.94	775,394.94	181,710.00	30.6%
	Transmission	30,000 kW / 19,000,000 kWH	1,219,670.93	1,603,280.93	383,610.00	31.5%

(a) Does not include Sales and Use Tax Rider, Consumption taxes, or Utility tax.

APCo Exhibit No. ___
Witness: SAS

**DIRECT TESTIMONY OF
SHELLI A. SLOAN
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUR-2022-00139**

APCo Exhibit No. ___
Witness: SAS

SUMMARY OF DIRECT TESTIMONY OF

SHELLI A. SLOAN

In my testimony I,

- Support the total company fuel forecast of APCo.
- Provide the estimate of APCo's total company Net Energy Requirement of 31,744.5 GWh, and includable cost of $878.5 million, to Company witness Castle for use in determining APCo's proposed Virginia jurisdictional fuel factor for the period November 2022 – October 2023.

APCo Exhibit No. ___
Witness: SAS

DIRECT TESTIMONY OF
SHELLI A. SLOAN
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUR-2022-00139

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

A. My name is Shelli A. Sloan. I am employed by AEPSC, a subsidiary of AEP, in the Corporate Planning and Budgeting organization as Director Financial Support and Special Projects. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

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 lead 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. WHAT ARE YOUR RESPONSIBILITIES AS DIRECTOR FINANCIAL SUPPORT AND SPECIAL PROJECTS?

A. As Director of Financial Support and Special Projects, I am responsible for directing the support of certain regulatory activities within the forecasting group, overseeing and compiling the preparation of earnings materials and projections, 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. With respect to this filing, I am responsible for deriving the sources and disposition of energy analysis for the forecast period.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY COMMISSION?

A. Yes, I have submitted testimony before the Commission on behalf of APCo, and I have testified and/or submitted testimony before the Public Service Commission of West Virginia on behalf of APCo and WPCo in fuel factor proceedings. In addition, I have filed testimony on behalf of Indiana Michigan Power before the Indiana Utility Regulatory Commission for fuel proceedings and before the Michigan Public Service Commission in power supply cost recovery proceedings.

Q. PLEASE SUMMARIZE YOUR TESTIMONY IN THIS PROCEEDING.

A. The purpose of my testimony is to:

- Provide an estimate of APCo's total company net energy requirement and includable cost for July 1, 2022 through October, 2022, (Bridge Period), and for November 1, 2022 through October 31, 2023, (Forecast Period); and
- Provide a description of the methodologies employed in order to arrive at the forecasted net energy requirement and includable cost.

I provided the estimate of APCo's total company net energy requirement of 31,744.5 GWh, and includable cost of $878.5 million, to Company witness Castle for use in determining APCo's proposed Virginia jurisdictional fuel factor.

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. I sponsor an estimate of APCo's net energy requirement and includable cost for the Forecast Period. Specifically, I sponsor:

- APCo Exhibit No. ___ (SAS) Schedule 1 - The estimate of the total company net energy requirement and includable cost for the Forecast Period;
- APCo Exhibit No. ___ (SAS) Schedule 2 - A total company sources and uses of energy statement for the Forecast Period;
- APCo Exhibit No. ___ (SAS) Schedule 3 - The projected Virginia sales to ultimate customers for the Forecast Period;
- APCo Exhibit No. ___ (SAS) Schedule 4 - A description of the NEC forecasting methodology; and
- APCo Exhibit No. ___ (SAS) Schedule 5 - The incremental Cost Calculation for RPS generation purchased from RPS Wind and Solar facilities as approved in the Company's 2021 VCEA Proceeding, and Non-RPS Wind Farms as calculated in prior fuel filings and the Fuel Recovery percentages for each RPS facility.

In addition, for the Bridge Period, I sponsor APCo Exhibit No. ___ (SAS) Schedule 6, an estimate of the total company net energy requirement and includable cost, a total company sources and uses of energy statement and a projection of Virginia sales to ultimate customers.

Q. HAVE THE DATA AND SCHEDULES YOU SPONSOR BEEN PREPARED IN A MANNER CONSISTENT WITH THE LAST FUEL FACTOR CASE THAT WAS FILED?

A. Yes, the data and schedules were prepared consistently with those presented in the Company's last fuel factor case, with the exception of the estimated price for natural gas used in the modeling, as described below, and the treatment of some of the Company's renewable resources. For renewable PPAs approved for recovery in the Company's 2021 VCEA Proceeding, the includable costs for these resources are the energy value, as defined, calculated, and approved in that case. For the Beech Ridge and Grand Ridge wind farms, which are not part of the Company's VCEA compliance resources, the includable costs are the "non-incremental costs," as calculated and approved in the 2015 APCo RPS-RAC Proceeding.

Q. WHEN WAS THE FORECAST FOR THIS FILING DEVELOPED?

A. The forecast is developed over several months utilizing the methodology described in APCo Exhibit No.____ (SAS) Schedule 4. 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; current market conditions are addressed by other Company witnesses. Because the different components of this 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. As one considers the comparisons and projections described throughout my testimony and in my exhibits, 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. For the forecast being utilized in this proceeding, the natural gas forecast was developed in early July 2022, during a time when natural gas prices were declining, while the final forecast was published in August 2022.

Q. WHY DID THE COMPANY CHOOSE TO CHANGE THE METHODOLOGY FOR CALCULATING THE ESTIMATED PRICE FOR NATURAL GAS UTILIZED FOR MODELING PURPOSES?

A. Due to the recent high volatility in the natural gas market, the natural gas forwards which were previously utilized by the Company for modeling purposes, are no longer reflective of a normalized market for near-term forecasting. Because of the magnitude of continual change in the forwards over the past few years, for market simulation, the Company chose to move to a natural gas price based on normalized weather, historical natural gas production, and consumption, and other economic data points. Company witness Stutler provides an overview of the natural gas market and the associated market volatility.

Q. WOULD YOU PLEASE DEFINE NET ENERGY REQUIREMENT AND INCLUDABLE COST?

A. Net energy requirement is defined, as in previous filings, as APCo's internal load (sales to ultimate customers, sales to firm wholesale customers, and losses). The includable cost is defined as the energy cost incurred to meet APCo's internal load requirements, including non-incremental wind costs as well as the financial settlement of PJM LSE (load serving entity) transmission losses, financial transmission rights (FTR) revenues, PJM Implicit Congestion Charges, and the off-system sales (OSS) margin credit. The components of the net energy requirement and includable cost are shown on APCo Exhibit No. ___ (SAS) Schedule 1.

APCo meets the energy requirements economically through a combination of its own generating sources and purchased power. Additional detail related to the sources and uses of energy and sales to ultimate customers is shown on APCo Exhibit No. ___ (SAS) Schedule 2 and APCo Exhibit No. ___ (SAS) Schedule 3, respectively.

Q. HAVE YOU PREPARED AN EXHIBIT THAT DESCRIBES THE METHODOLOGY REFERENCED ABOVE?

A. Yes. Please refer to APCo Exhibit No. ___ (SAS) Schedule 4.

Q. PLEASE DESCRIBE THE COMPANY'S RENEWABLE GENERATION RESOURCES INCLUDED IN THIS FILING.

A. The Company has wind PPAs with Camp Grove Wind Farm, Fowler Ridge Wind Farm, and Bluff Point Wind Farm. These three legacy wind PPAs and solar PPAs with Leatherwood, Wytheville, and Depot were subject to prudency and approved as part of the Company's 2021 VCEA Proceeding. The includable costs for these RPS generation resources in regards to this filing are the energy value, as defined, calculated and approved in that case.

In addition, the Company has wind PPAs with Beech Ridge and Grand Ridge wind farms, which are included in this filing as Non-RPS facilities and are calculated for recovery as approved in the 2015 APCo RPS-RAC Proceeding.

Q. PLEASE DISCUSS HOW YOU HAVE SHOWN THE FORECASTED PURCHASE POWER RPS AND NON-RPS FACILITIES COSTS IN THIS FILING.

A. The total energy value for the RPS PPAs are included in NEC on APCo Exhibit No. ___ (SAS) Schedule 1, line 4. The amount of the energy costs from these contracts that cannot be included are removed on APCo Exhibit No. ___ (SAS) Schedule 1, line 9, leaving the allowable energy costs of these contracts in the fuel filing. The energy from the renewables facilities is shown on APCo Exhibit No. ___ (SAS) Schedule 1, line 22.

The total generation cost of the Non-RPS are included in NEC on APCo Exhibit No. ___ (SAS) Schedule 1, line 5. The amount of the generation costs from these contracts that cannot be included are removed on APCo Exhibit No. ___ (SAS) Schedule 1, line 10, leaving the allowable costs of these contracts in the fuel filing. The energy from the renewables facilities is shown on APCo Exhibit No. ___ (SAS) Schedule 1, line 23.

Q. PLEASE DISCUSS HOW THE EXCLUDED ENERGY COSTS FOR THE RENEWABLE FACILITIES WERE CALCULATED.

A. APCo Exhibit No. ___ (SAS) Schedule 5, Page 1 of 2, shows the incremental costs for the Non-RPS Farms which were calculated consistent with the methodology that was approved by the Commission in the 2015 APCo RPS-RAC Proceeding using the current percentage from the June 2022 monthly fuel factor deferral accounting process. These non-incremental costs are equal to the replacement costs APCo would have incurred had the wind contracts not been in place.

APCo Exhibit No. ___ (SAS) Schedule 5, Page 2 of 2, reflects the allowable percentages (Fuel Recovery Percent) for each RPS facility as approved in the Company's 2021 VCEA Proceeding.

Q. PLEASE DESCRIBE HOW THE FORECAST OF THE OFF-SYSTEM SALES MARGIN CREDIT WAS DERIVED.

A. OSS volume is a function of APCo's forecasted generation and committed purchases (*i.e.*, OVEC, Summersville hydro, solar and wind) as determined by the *PLEXOS*® simulation model and hour-by-hour internal load. An off-system sale is forecasted to occur during a given hour when the sum of APCo'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 priced according to forecasted market prices. The total forecast of OSS revenues is divided between cost recovery and net realization or margin.

These margins consist of both physical and non-physical transactions in the wholesale market. The margin represents the value that remains after subtracting the variable cost incurred to make off-system sales from the total revenue realized. This definition is consistent with how these margins have been defined as off-system sales margins are included as a credit to fuel costs. The incremental transmission line loss margins, FTR Revenues and PJM Implicit Congestion Charges on lines 12, 14 and 15 of APCo Exhibit No. ___ (SAS) Schedule 1 have been adjusted out of the off-system sales margin, and a 75% factor has been applied to the remaining margin.

Q. WHAT IS THE NET ENERGY REQUIREMENT AND INCLUDABLE COST FOR THE FORECAST PERIOD FOR APCO AS DETERMINED BY THE METHODOLOGY DESCRIBED IN APCO EXHIBIT NO. ___ (SAS) SCHEDULE 4?

A. As shown on APCo Exhibit No. ___ (SAS) Schedule 1, line 28, APCo's net energy requirement is 31,744.5 GWh. APCo Exhibit No. ___ (SAS) Schedule 1, line 16 also shows the total Company Includable Cost is $878.5 million. The estimated per-unit cost is 27.67 mills/kWh (or 2.77 ¢/kWh), before consideration for any line losses. This rate is used in the determination of the proposed Virginia jurisdictional fuel factor as developed by Company witness Castle in this proceeding.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

APPALACHIAN POWER COMPANY
Projected Net Energy Requirement
and Includable Cost
For the 12 Months Ending October 2023

Line No.	Net Energy Cost ($000)	Nov 2022	Dec 2022	Jan 2023	Feb 2023	Mar 2023	Apr 2023	May 2023	Jun 2023	Jul 2023	Aug 2023	Sep 2023	Oct 2023	12 Mos. Ending 10/31/2023
1	Fossil Generation (A/C 151)	41,445.2	71,895.8	88,159.4	73,657.5	73,387.0	58,043.7	47,345.3	70,321.5	70,000.0	70,626.3	42,690.6	50,734.2	758,306.8
2	Plus:													
3	Purchases (total cost)	43,979.1	20,965.8	9,329.7	12,362.2	11,497.7	14,067.7	20,986.9	9,275.5	14,432.6	11,035.8	21,004.7	14,848.9	203,786.5
4	Purchase Power RPS Facilities	4,971.5	5,318.6	5,607.4	4,918.5	5,168.0	5,048.1	3,941.3	3,051.2	2,141.7	2,128.6	2,943.1	4,428.3	49,666.4
5	Purchase Power Non-RPS Facilities (total)	4,992.8	5,217.0	5,827.3	5,389.0	5,720.6	5,116.8	3,851.4	2,883.6	2,051.1	2,071.9	2,499.8	3,883.8	49,305.1
6	Less:													
7	Energy Generated for Off-System Sales (A/C 151)	2,177.0	9,491.2	13,355.4	10,005.5	14,603.2	11,410.6	3,612.9	14,276.7	7,260.9	8,635.8	2,994.8	5,771.5	103,595.6
8	Total Net Energy Cost	93,211.7	93,905.9	95,568.4	86,321.7	81,170.2	70,865.8	72,312.0	71,255.1	81,364.6	77,226.8	66,143.3	68,123.7	957,469.1
9	Purchase Power RPS Facilities(Energy amount Not Recovered in Fuel)	(2,331.2)	(2,491.5)	(2,638.4)	(2,313.0)	(2,420.2)	(2,375.3)	(1,850.0)	(1,431.6)	(1,011.0)	(1,000.0)	(1,375.6)	(2,078.2)	(23,317.0)
10	Purchase Power Non-RPS Facilities (Incremental amount Not Recovered in Fuel)	(1,861.8)	(1,945.2)	(2,172.7)	(2,009.3)	(2,132.9)	(1,907.8)	(1,361.4)	(1,075.1)	(764.8)	(772.5)	(932.0)	(1,448.1)	(18,383.5)
11	75% of Off-System Sales Margin Credit	(70.0)	(4,470.9)	(6,301.6)	(4,101.7)	(6,120.8)	(2,998.5)	(686.1)	(1,919.9)	(253.8)	(114.5)	(512.3)	(830.2)	(28,378.4)
12	100% of Incremental Transmission Line Loss Margins	(1,856.6)	(2,372.0)	(2,167.4)	(1,516.7)	(1,441.0)	(678.2)	209.2	(349.6)	281.2	305.4	411.5	(212.1)	(9,384.4)
13	PJM LSE Transmission Losses	895.1	1,012.4	1,023.5	894.5	1,102.3	995.8	910.4	766.8	800.6	837.2	782.2	815.1	10,835.9
14	FTR Revenues	(1,715.4)	(1,881.7)	(2,082.6)	(2,135.2)	(2,113.2)	(2,012.5)	(2,000.1)	(1,895.7)	(1,851.1)	(2,129.8)	(1,740.2)	(1,732.0)	(23,289.4)
15	PJM Implicit Congestion Charges	1,065.7	1,106.7	1,151.0	1,121.9	1,060.7	1,018.2	1,027.9	1,076.8	1,109.9	1,097.6	1,064.2	1,043.4	12,943.9
16	Includable Cost	87,337.7	82,863.8	82,380.0	76,262.2	69,105.1	62,911.4	68,562.0	66,426.7	79,675.6	75,449.9	63,841.1	63,680.7	878,496.3
	Net Energy Requirement (GWH)													
17	Fossil Generation	1,455.1	2,582.1	3,206.6	2,647.3	2,654.6	2,056.2	1,667.7	2,463.4	2,422.4	2,481.2	1,540.5	1,868.2	27,045.3
18	Hydro Generation	49.7	50.1	59.6	63.0	64.1	59.5	55.0	35.6	25.5	23.4	30.7	38.7	554.8
19	Total Generation	1,504.9	2,632.2	3,266.1	2,710.3	2,718.6	2,115.7	1,722.7	2,499.1	2,447.9	2,504.5	1,571.3	1,906.9	27,600.1
20	Plus:													
21	Purchases	967.0	490.5	288.2	344.1	353.9	383.9	551.4	282.9	421.5	372.9	745.9	471.5	5,673.5
22	Purchases - RPS Facilities	94.4	95.4	97.4	86.8	98.2	96.2	77.6	62.1	44.5	43.7	59.5	83.9	939.8
23	Purchases - Non-RPS Facilities	51.8	50.2	55.5	50.4	59.1	54.7	39.3	30.0	20.3	18.2	27.2	42.6	499.2
24	PJM Marginal Losses	62.3	71.5	78.8	68.6	65.4	54.3	55.8	58.3	66.1	65.5	56.5	56.4	759.3
25	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Less:													
27	Energy Purchased and Generated for Off-System Sales	72.8	341.0	494.5	385.4	556.2	420.1	122.4	504.0	242.9	284.5	100.1	203.3	3,727.3
28	Total Net Energy Requirement	2,607.5	2,988.8	3,291.3	2,874.9	2,739.0	2,284.6	2,324.5	2,428.3	2,757.4	2,720.4	2,360.1	2,357.9	31,744.5
29	Net Energy Cost (m/kwh)	33.50	27.63	25.03	26.53	25.23	27.54	29.50	27.36	28.90	27.74	27.05	27.01	27.67

APCo Exhibit No. ______
Witness: SAS
Schedule 1
Page 1 of 1

220920035

APCo Exhibit No. ____
Witness: SAS
Schedule 2
Page 1 of 1

22092035

APPALACHIAN POWER COMPANY
Sources and Uses of Energy
For the 12 Months Ending October 2023
(GWH)

Line No.	Sources of Energy	Nov 2022	Dec 2022	Jan 2023	Feb 2023	Mar 2023	Apr 2023	May 2023	Jun 2023	Jul 2023	Aug 2023	Sep 2023	Oct 2023	12 Mos. Ending 10/31/2023
	Fossil Generation by Plant:													
	AMOS	423.6	1,427.6	1,807.3	1,450.7	1,568.1	1,289.9	931.6	1,467.6	1,446.3	1,385.9	1,066.3	939.1	15,204.1
	CEREDO	0.9	9.5	30.6	20.1	7.5	0.2	4.3	12.5	10.1	3.9	3.3	16.8	119.5
	CLINCH RIVER - GAS	6.7	37.7	-	5.4	16.1	3.9	-	-	-	-	-	8.4	78.2
	DRESDEN	413.3	462.3	451.3	422.4	423.4	199.2	21.6	376.9	396.1	390.3	373.2	308.7	4,238.8
	MOUNTAINEER	610.6	645.1	917.3	748.7	639.4	563.0	710.2	606.5	569.8	701.1	97.7	595.2	7,404.6
	Total Fossil Generation	1,455.1	2,582.1	3,206.8	2,647.3	2,654.6	2,056.2	1,667.7	2,463.4	2,422.4	2,481.2	1,540.5	1,868.2	27,045.3
	Hydro Generation	49.7	50.1	59.6	63.0	64.1	59.5	55.0	35.6	25.5	23.4	30.7	38.7	554.8
1	Total Generation	1,504.9	2,632.2	3,266.1	2,710.3	2,718.6	2,115.7	1,722.7	2,499.1	2,447.9	2,504.5	1,571.3	1,906.9	27,600.1
2	Purchased Power:													
3	Purchased Power	967.0	490.5	288.2	344.1	353.9	383.9	551.4	282.9	421.5	372.9	745.9	471.5	5,673.5
4	Purchases - RPS Facilities	94.4	95.4	97.4	86.8	98.2	96.2	77.6	62.1	44.5	43.7	59.5	83.9	939.8
5	Purchases - Non-RPS Facilities	51.8	50.2	55.5	50.4	59.1	54.7	39.3	30.0	20.3	18.2	27.2	42.6	499.2
6	Other *													-
7	Total Purchased Power	1,113.1	636.1	441.1	481.4	511.1	534.7	668.4	375.0	486.3	434.8	832.6	597.9	7,112.5
8	PJM Marginal losses	62.3	71.5	78.6	68.6	65.4	54.3	55.8	58.3	66.1	65.5	56.5	56.4	759.3
9	Total Sources of Energy	2,680.3	3,339.8	3,785.8	3,260.3	3,295.2	2,704.7	2,446.9	2,932.3	3,000.3	3,004.8	2,460.3	2,561.2	35,471.9
	Uses of Energy													
	Sales of Ultimate Customers:													
10	Residential	897.2	1,148.0	1,478.3	1,158.2	977.7	714.7	685.8	733.5	935.1	869.5	682.8	654.4	10,935.3
11	Commercial	520.0	438.2	572.9	471.4	477.0	416.2	492.6	512.0	576.8	538.8	474.9	500.7	5,991.6
12	Industrial	798.3	667.2	732.6	678.5	742.0	683.2	770.4	744.4	761.4	749.0	718.4	779.4	8,824.8
13	All Other Ultimates	76.9	65.0	80.2	69.3	71.7	62.2	70.9	69.1	69.3	67.2	68.3	72.6	842.6
14	Total Sales to Ultimates	2,292.4	2,318.4	2,864.0	2,377.5	2,268.4	1,876.4	2,019.8	2,059.0	2,342.6	2,224.5	1,944.4	2,007.1	26,594.3
15	Associated Companies	139.5	170.2	179.0	160.5	140.1	127.5	131.5	134.7	152.2	151.5	133.6	128.5	1,749.0
16	Municipals and Cooperatives	88.2	98.9	107.8	96.2	91.7	81.5	85.5	94.6	105.8	105.1	92.1	84.9	1,132.3
17	Losses	87.4	411.3	140.4	240.8	238.8	199.3	87.6	139.9	156.7	239.3	190.0	137.4	2,268.9
18	Total Internal	2,607.5	2,998.8	3,291.3	2,874.9	2,739.0	2,284.6	2,324.5	2,428.3	2,757.4	2,720.4	2,360.1	2,357.9	31,744.5
19	Off-System Sales	72.8	341.0	494.5	385.4	556.2	420.1	122.4	504.0	242.9	284.5	100.1	203.3	3,727.3
20	Total Uses of Energy	2,680.3	3,339.8	3,785.8	3,260.3	3,295.2	2,704.7	2,446.9	2,932.3	3,000.3	3,004.8	2,460.3	2,561.2	35,471.9

* Other represents difference due to rounding.

APCo Exhibit No. ____
Witness: SAS
Schedule 3
Page 1 of 1

2209290035

APPALACHIAN POWER COMPANY
Sales to Ultimate Customers - Virginia*
For the 12 Months Ending October 2023
(GWH)

Line No.	Sales to Ultimate Customers	Nov 2022	Dec 2022	Jan 2023	Feb 2023	Mar 2023	Apr 2023	May 2023	Jun 2023	Jul 2023	Aug 2023	Sep 2023	Oct 2023	12 Mos. Ending 10/31/2023
1	Residential	518.1	649.9	831.4	650.4	547.6	404.3	389.9	410.0	524.8	477.8	386.7	371.8	6,162.5
2	Commercial	246.0	205.1	268.4	224.8	219.2	190.5	228.3	235.5	269.3	247.6	218.5	227.0	2,780.3
3	Industrial	434.0	361.2	390.8	369.9	409.5	385.2	432.0	420.7	425.3	418.6	402.1	427.3	4,876.5
4	Virginia Jurisdictional Sales	1,198.1	1,216.2	1,490.6	1,245.1	1,176.2	980.0	1,050.2	1,066.2	1,219.3	1,144.0	1,007.3	1,026.0	13,819.4
5	All Other Ultimates	73.9	62.0	77.1	66.8	69.1	60.1	68.9	67.3	67.4	65.1	66.0	69.9	813.6
6	Total Sales to Ultimates	1,272.0	1,278.2	1,567.7	1,311.9	1,245.3	1,040.1	1,119.2	1,133.5	1,286.7	1,209.2	1,073.3	1,095.9	14,633.0

*Excludes Choice Customers

Development of NEC Forecast
In Virginia S.C.C. Case No. PUR-2022-00139

I. Overview

The preparation of Appalachian Power Company's (APCo) Net Energy Cost (NEC) forecast requires a projection of APCo'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 Resource Planning Departments developed the generation and off-system sales forecast.

The internal load forecast reflects an analysis of the economy and the unique factors that influence individual customers or customer classes that APCo serves. A forecast of generation (net energy output) from APCo's generating units and purchased power was developed for the Forecast Period to meet APCo's total system load obligations. APCo'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.

II. Cost of Fuel Consumed

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

Specifically, the cost of coal consumed for each of APCo'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 natural gas price as calculated by using historic production and consumption values, normalized weather, and other economic variables. The output of the gas units is multiplied by the expected price of natural gas.

II. 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 Non-RPS (Beech Ridge and Grand Ridge wind farms) and RPS facilities (Bluff Point, Camp Grove, and Fowler Ridge). Three RPS solar facilities that are load reducers are included in Purchased Power as well (Leatherwood, Wytheville, and Depot). Other purchases are assigned, based on cost, to either internal load or off-system sales via economic dispatch.

APCo Exhibit No. _____
Witness: SAS
Schedule 5
Page 1 of 2

APPALACHIAN POWER COMPANY
Incremental/Non-Incremental Cost Calculation for
Non-RPS Farms
Beech Ridge & Grand Ridge Wind Farms

Line	Item	2022
1	Wind Purchase Power Agreement Payments	$ 46,810,565
2	Capacity Value	$ (3,235,477)
3	Energy Value	$ (25,277,200)
4	Off-System Sales (OSS) Margins	$ (844,473)
5	**Incremental Cost** (Sum Ln 1:Ln 4)	$ 17,453,415
6	**Incremental Percent** (Ln 5/Ln1)	**37.29%**
7	**Non-Incremental Cost** (Sum Ln 1-Ln 5)	$ 29,357,151
8	**Non-Incremental Percent** (1-Ln 5)	**62.71%**

Note: All values shown are on an APCo total company basis.
Percentages calculated as approved in PUE-2015-00034

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APPALACHIAN POWER COMPANY
Incremental/Non-Incremental Cost Calculation for
RPS Farms
Camp Grove, Fowler Ridge & Bluff Point Wind Farms
Wytheville, Leatherwood, and Depot Solar Facilities

Line	Item	Bluff Point	Camp Grove	Fowler Ridge III
1	**Non-Fuel Recovery Percent**	39.93%	49.99%	49.92%
2	**Fuel Recovery Percent**	60.07%	50.01%	50.08%

Line	Item	Depot	Leatherwood	Wytheville
1	**Non-Fuel Recovery Percent**	59.92%	48.63%	48.80%
2	**Fuel Recovery Percent**	40.08%	51.37%	51.20%

Note: All values shown are on an APCo total company basis.
Percentages claculated as appoved in PUR-2021-00206

APCo Exhibit No. _____
Witness: SAS
Schedule 6

APPALACHIAN POWER COMPANY
Projected Net Energy Requirement
and Includable Cost
For the period July 2022 - October 2022

Line No.	Net Energy Cost ($000)	Jul 2022	Aug 2022	Sep 2022	Oct 2022
1	Fossil Generation (A/C 151)	68,023.6	67,690.5	57,479.1	43,055.6
2	Plus:				
3	Purchases (total cost)	22,014.2	19,074.6	15,806.8	31,623.6
4	Purchase Power RPS Facilities (Amount Recovered in Fuel)	2,120.4	2,048.0	2,879.3	4,307.6
5	Purchase Power Non-RPS Facilities (Amount Recovered in Fuel)	1,950.2	1,970.8	2,569.1	3,851.1
6	Less:				
7	Energy Generated for Off-System Sales (A/C 151)	7,135.3	6,210.5	7,946.1	1,668.2
8	Total Net Energy Cost	86,973.1	84,573.5	70,788.3	81,169.7
9	Purchase Power RPS Facilities(Amount Not Recovered in Fuel)	(1,001.2)	(960.7)	(1,345.4)	(2,021.4)
10	Purchase Power Non-RPS Facilities (Amount Not Recovered in Fuel)	(727.1)	(734.8)	(957.9)	(1,435.9)
11	75% of Off-System Sales Margin Credit	(6,067.7)	(933.3)	(2,145.3)	(68.7)
12	100% of Incremental Transmission Line Loss Margins	(4,702.7)	(623.0)	(964.2)	(1,425.3)
13	PJM LSE Transmission Losses	800.6	837.2	782.2	815.1
14	FTR Revenues	(2,269.1)	(2,102.5)	(1,814.0)	(1,675.8)
15	PJM Implicit Congestion Charges	1,109.9	1,097.6	1,064.2	1,043.4
16	Includable Cost	74,115.7	81,154.0	65,407.9	76,401.1
	Net Energy Requirement (GWH)				
17	Fossil Generation	2,432.9	2,424.4	2,108.7	1,553.3
18	Hydro Generation	23.9	24.5	26.4	34.9
19	Total Generation	2,456.8	2,448.8	2,135.1	1,588.2
20	Plus:				
21	Purchases	434.2	376.3	392.0	656.6
22	Purchases - RPS Facilities	44.6	43.8	59.5	83.9
23	Purchases - Non-RPS Facilities	20.3	18.2	27.2	42.6
24	PJM Marginal Losses	66.4	65.9	57.3	56.4
25	Other	-	-	-	-
26	Less:				
27	Energy Purchased and Generated for Off-System Sales	248.9	215.5	286.5	61.6
28	Total Net Energy Requirement	2,773.3	2,737.4	2,384.6	2,366.2
29	Net Energy Cost (m/kwh)	26.72	29.65	27.43	32.29

APPALACHIAN POWER COMPANY
Sources and Uses of Energy
For the period July 2022 - October 2022
(GWH)

Line No.	Sources of Energy	Jul 2022	Aug 2022	Sep 2022	Oct 2022
	Fossil Generation by Plant:				
	AMOS	1,538.8	1,529.4	1,405.0	241.1
	CEREDO	16.5	6.3	8.8	13.4
	CLINCH RIVER - GAS	-	-	-	38.7
	DRESDEN	369.5	310.8	218.4	436.3
	MOUNTAINEER	508.2	577.8	476.5	823.8
1	Total Fossil Generation	2,432.9	2,424.4	2,108.7	1,553.3
	Hydro Generation	23.9	24.5	26.4	34.9
	Total Generation	2,456.8	2,448.8	2,135.1	1,588.2
2	Purchased Power:				
3	Purchased Power	434.2	376.3	392.0	656.6
4	Purchases - RPS Facilities	44.6	43.8	59.5	83.9
5	Purchases - Non-RPS Facilities	20.3	18.2	27.2	42.6
6	Other *	-	-	-	-
7	Total Purchased Power	499.1	438.2	478.7	783.1
8	PJM Marginal losses	66.4	65.9	57.3	56.4
9	Total Sources of Energy	3,022.2	2,952.9	2,671.1	2,427.7
	Uses of Energy				
	Sales of Ultimate Customers:				
10	Residential	955.3	883.3	695.5	646.4
11	Commercial	579.9	538.9	475.0	488.3
12	Industrial	759.0	743.2	715.5	767.3
13	All Other Ultimates	69.5	66.8	68.1	70.8
14	Total Sales to Ultimates	2,363.7	2,232.2	1,954.0	1,972.8
15	Associated Companies	152.7	152.0	133.9	128.5
16	Municipals and Cooperatives	105.7	105.1	92.2	85.0
17	Losses	151.2	248.2	204.5	179.9
18	Total Internal	2,773.3	2,737.4	2,384.6	2,366.2
19	Off-System Sales	248.9	215.5	286.5	61.6
20	Total Uses of Energy	3,022.2	2,952.9	2,671.1	2,427.7

* Other represents difference due to rounding.

220320035

APCo Exhibit No. _____
Witness: SAS
Schedule 6
Page 3 of 3

APPALACHIAN POWER COMPANY
Sales to Ultimate Customers - Virginia*
For the period July 2022 - October 2022
(GWH)

Line No.	Sales to Ultimate Customers	Jul 2022	Aug 2022	Sep 2022	Oct 2022
1	Residential	536.3	485.8	394.7	367.3
2	Commercial	276.0	252.0	222.9	224.5
3	Industrial	418.3	409.6	396.2	415.9
4	Virginia Jurisdictional Sales	1,230.6	1,147.3	1,013.8	1,007.7
5	All Other Ultimates	67.6	64.8	65.8	68.0
6	Total Sales to Ultimates	1,298.2	1,212.1	1,079.6	1,075.8

*Excludes Choice Customers

APCo Exhibit No. ___
Witness: KKC

DIRECT TESTIMONY OF
KIMBERLY K. CHILCOTE
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUR-2022-00139

APCo Exhibit No. ___
Witness: KKC

Summary of Direct Testimony of

KIMBERLY K. CHILCOTE

In my direct testimony I

- Discuss APCo's coal purchasing strategy;
- Provide an overview of the coal market in which APCo procures coal;
- Describe the coal delivery forecast for the twelve-month period from November 1, 2022 through October 31, 2023 (Forecast Period); and
- Describe APCo's portfolio of coal supply agreements.

APCo Exhibit No. ___
Witness: KKC

DIRECT TESTIMONY OF
KIMBERLY K. CHILCOTE
FOR APPALACHIAN POWER COMPANY
IN VIRGINIA S.C.C. CASE NO. PUR-2022-00139

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

A. My name is Kimberly K. Chilcote. I am employed by AEPSC, a subsidiary of AEP, in the regulated Commercial Operations organization as Coal Procurement Manager. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I graduated from the University of Dayton in 1992 with a Bachelor of Chemical Engineering Degree.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. I joined AEP in 1992 as an Assistant Chemist at Columbus Southern Power Company's (CSP) Conesville Plant. In 2004, I transferred to the fuels group as a Coordinator and was primarily responsible for assessing and reviewing the coal qualities of the coal purchased by the procurement department. In 2007, I transferred to the Fuel Procurement group and was responsible for the purchase and shipment of all of the Powder River Basin Coal for the AEP System power plants. In 2008, I became responsible for purchasing coal for CSP and Ohio Power Company, which merged to become AEP Ohio. In 2010, I was promoted to Manager of Coal Procurement for AEP Ohio and Kentucky Power Company. In 2014, I joined AEP Generation Resources with responsibilities for purchasing coal, natural gas and consumables for AEP's unregulated plants. In 2020, I accepted a position in the regulated Commercial Operations organization in the coal and reagents transportation team. I was promoted to my current position as Coal Procurement Manager in May of 2021.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY AS COAL PROCUREMENT MANAGER FOR AEPSC?

A. I am responsible for managing coal procurement, contract oversight, and inventory management activities for several AEP operating companies, including APCo.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY AGENCIES?

A. Yes. I filed testimony before the Commission in Case No. PUR-2021-00205. I have also testified before the Kentucky Public Service Commission on behalf of Kentucky Power Company in its fuel review proceedings.

I. PURPOSE

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

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

1) Discuss APCo's coal purchasing strategy;
2) Provide an overview of the coal market in which APCo procures coal;
3) Describe the coal delivery forecast for the twelve-month period from November 1, 2022 through October 31, 2023 (Forecast Period); and
4) Describe APCo's portfolio of coal supply agreements.

Q. ARE YOU SPONSORING ANY SCHEDULES?

A. Yes. I am sponsoring APCo Exhibit No. ___ (KKC) Schedule 1, which is a list of long-term coal supply agreements that will be in effect during the Forecast Period.

II. COAL PURCHASING STRATEGY

Q. PLEASE DESCRIBE APCO'S COAL PURCHASING STRATEGY.

A. Coal delivery requirements are determined by taking into account existing coal inventory, forecasted coal consumption, and adjustments for contingencies related to planned as well as unplanned outages to maintain adequate coal inventory levels.

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, which help to determine when to issue RFPs or to make prompt purchases from the market if required and available. RFPs specify the quality and logistical parameters sought for each plant. From qualifying offers, APCo makes its selection of the coal needed to meet its requirements, based on the lowest reasonable delivered cost, including the consideration of price, coal quality, ability to deliver, past performance, and the financial status of suppliers.

Additionally, the Company evaluates unsolicited offers, monitors coal markets for availability, and considers coal supplies from non-traditional markets as necessary. The Company evaluates unsolicited offers against published market prices and recent solicitation results to ensure reliable supplies of coal at reasonable prices.

Lastly, the Company relies on the physical inventory to be used during periods of high consumption and to minimize supply disruptions. Supply disruptions can be caused by events such as power plant outages, inclement weather, river levels, mine production challenges and outages, and shortages of equipment and labor.

Q. WHAT IS APCO'S STRATEGY FOR PROCURING COAL VIA LONG-TERM AND SHORT-TERM AGREEMENTS?

A. The Company consumes both high-sulfur Northern Appalachian (NAPP) coal and low-sulfur Central Appalachian (CAPP) coal in its coal-fired plants to meet the requirements of the electric generating units and the installed environmental equipment (*i.e.* flue gas desulfurization design specifications). The Company uses a portfolio of both short-term agreements (with a term of one year or less) and long-term coal supply agreements to gradually increase the amount of contracted coal as the Company approaches a given period. With the current global situation and unpredictable natural gas prices, the generation demands and the associated coal demands of the plants are more volatile than they have been in the past several years, and agreements of varying lengths help to mitigate some of this volatility.

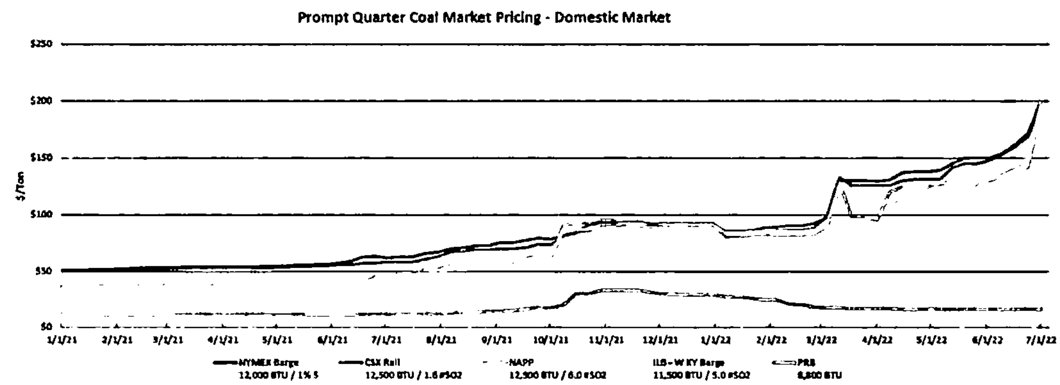
III. <u>MARKET OVERVIEW</u>

Q. PLEASE DESCRIBE RECENT CHANGES IN THE COAL MARKET.

A. Coal prices were generally flat during the first half of 2021, but domestic and global coal prices increased rapidly in the second half of 2021 as demand 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 developments in the natural gas market for 2021 and through mid-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 uncommitted supplies to significantly tighten from all coal basins in the second half of 2021 and thus far in 2022, resulting in sharply higher coal prices. The supply of coal is projected to be constrained throughout the remainder of 2022 and into 2023.

As can be seen in Figure 1 below, a comparison of prices for the coal markets from the beginning of 2021 through the first half of 2022 shows the drastic price increases in all of the basins. Coal specifications are generally defined through heat content in British Thermal Units (Btu) and sulfur content defined as sulfur dioxide (SO_2) per pound of coal. Low-sulfur 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 $195.00 per ton. High-sulfur NAPP coal (12,500 Btu per lb., 6 lbs. SO_2) markets also increased during the same period from $36.50 per ton to $200.00 per ton. Illinois Basin (ILB) coal (11,500 Btu per lb., 5.00 lbs. SO_2) and Powder River Basin (PRB) coal (8,800 Btu per lb., .80 lbs. SO_2), which historically have not been used by the Company in material quantities, also increased over the same period. High demand and limited coal availability in 2022 are projected to keep coal prices at elevated levels (see Figure 1).

Figure 1: Per Argus-McCloskey



Q. HOW HAS THE COAL EXPORT MARKET AFFECTED THE COMPANY'S ABILITY TO PROCURE COAL IN 2022, AND GOING FORWARD?

A. With high natural gas prices in Europe, U.S. coal became economic for European utilities, which led to an increase in the demand for U.S. coal and coal suppliers in the U.S. began dedicating portions of their production to the export markets. In September 2021, export coal prices had increased to approximately $200.00 per ton from mid-year pricing of approximately $100.00 per ton, representing a 100% increase in price in three months. Recently, export coal prices have been as high as $450.00 per ton, and averaged approximately $280.00 per ton for the first six months of 2022. This demand for export coal will continue to strain the domestic coal supply. APCo continues to work with coal suppliers and evaluate new production opportunities.

Q. WHAT EFFECT DID RECENT MARKET CONDITIONS HAVE ON THE PRICE APCO PAID FOR COAL?

A. Based on current market conditions and contracts entered into for 2022 and beyond, the price the Company will pay for coal in the next few years will be higher than what has been paid historically. For purchases made in the latter part of 2021, the price of the coal was higher than previously paid by the Company in recent years. Delivered coal prices were 0.44% higher per ton in 2021 than prices paid for coal delivered in 2020. Of this increase, 1.99% was coal related and -1.55% was transportation related.

IV. COAL DELIVERY FORECAST

Q. HAS AEPSC PREPARED A FORECAST OF DELIVERED COAL COSTS FOR APCO'S POWER PLANTS FOR THE PERIOD NOVEMBER 2022 THROUGH OCTOBER 2023?

A. Yes. Data, prepared as of June 2022, by coal purchase type (Committed, Non-Committed, and Total) and price per ton (FOB mine), Transportation, and Total Delivered Cost, along with the total weighted average forecasted cost of coal delivered to APCo's generating stations, on a cents per million British Thermal Units (¢/MMBTU) basis, for the period November 2022 through October 2023, was provided to Company witness Sloan for use in preparing APCo's forecast.

This forecast estimates total costs of delivered coal (on a total company weighted average basis) to APCo's plants, over the period of November 2022 through October 2023, of $60.46 per ton, or 272.22 ¢/MMBTU.

Q. IN PREPARING THE FORECAST OF DELIVERED COAL, HAS APCO CHANGED THE METHODOLOGY IT HAS HISTORICALLY USED IN THE DEVELOPMENT OF SUCH FORECASTS?

A. No. The methodology utilized in this forecast is consistent with the methodology that has been used by APCo and presented to this Commission in previous proceedings.

V. PORTFOLIO OF COAL SUPPLY AGREEMENTS

Q. PLEASE DESCRIBE APCO'S PORTFOLIO OF LONG-TERM COAL SUPPLY AGREEMENTS.

A. APCo, as of July 1, 2022, has sixteen long-term agreements: seven for the supply of high sulfur coal and nine for the supply of low sulfur coal. Some of these agreements begin deliveries beyond the Forecast Period, but are included for reference. In 2021, the Company added three new high sulfur suppliers and six new low sulfur suppliers to the portfolio. Information regarding the Company's long-term coal supply agreements is contained in APCo Exhibit No. ___ (KKC) Schedule 1.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

APCo Exhibit No. _____
Witness: KKC
Schedule 1
Page 1 of 1

APPALACHIAN POWER COMPANY
2022 VIRGINIA FUEL FACTOR FILING
SUMMARY OF LONG TERM COAL SUPPLY AGREEMENTS EFFECTIVE AS OF July 1, 2022

					Contracted Quality Specifications			
Supplier	Contract Number	Delivery Start Date	Plant(s)	Transportation Options	BTU	Moisture	Ash	Lbs SO2/ MMBTU
Consolidation Coal Company	02-10-12-900	1/1/2012	Amos, Mountaineer	Barge/Rail	11,800	9.0%	13.0%	7.25
Alliance Coal, LLC	02-10-19-9M2	1/1/2021	Mountaineer	Barge	12,600	7.0%	9.0%	4.80
Alliance Coal, LLC	02-10-21-9M2	1/1/2023	Mountaineer	Barge	12,600	7.0%	9.3%	5.60
Alliance Coal, LLC	02-10-21-9M5	1/1/2023	Mountaineer	Barge	11,450	12.3%	9.3%	5.20
Consol Pennsulvania Coal Company, LLC	02-10-21-001	1/20/2022	Amos	Rail	12,900	4.8%	7.9%	4.82
Iron Coal Sales, LLC	02-10-21-9M3	1/1/2022	Mountaineer	Barge	12,900	5.0%	9.0%	5.00
Rosebud Mining Company	02-10-21-9M6	1/1/2022	Mountaineer	Barge	11,900	8.0%	11.5%	5.50
Blackhawk Coal Sales, LLC	02-40-21-9M1	1/1/2022	Amos	Barge	12,000	7.0%	13.0%	1.45
Blackhawk Coal Sales, LLC	02-40-21-9M4	1/1/2022	Amos	Barge	12,000	7.0%	13.5%	1.45
Contura Coal Sales, LLC*	02-40-19-9M5	1/1/2021	Amos	Barge	12,000	10.0%	12.0%	1.60
Alpha Thermal Coal Sales Company	02-40-21-9M2	1/1/2022	Amos	Barge	12,400	8.0%	10.0%	1.60
Alpha Thermal Coal Sales Company	02-40-21-9M3	1/1/2023	Amos	Barge	12,400	8.0%	12.5%	1.70
Investment Marketing Company	02-40-22-004	7/1/2022	Amos	Barge	12,000	8.5,%	13.0%	1.67
Lexington Coal Company, LLC	02-40-21-003	1/1/2022	Amos	Rail	12,250	7.0%	12.5%	1.55
River Trading Company	02-40-21-002	1/1/2022	Amos	Barge	12,500	7.0%	8.0%	2.30
Case Coal Sales, LLC	02-40-21-004	2/1/2022	Amos	Barge	12,000	10.0%	13.0%	1.67

* Contract assigned to Alpha Thermal Coal Sales Company