DATA REQUEST

KPSC PHDR_1	Refer to the February 13, 2024 Hearing Testimony of Alex E. Vaughan (Hearing Video Transcript 11:32:13). a. Provide all documentation, including but not limited to, monthly discussion documents, reports, summaries, meeting minutes, and correspondence, regarding Kentucky Power and American Electric Power (AEP) personnel discussions about coal inventory shortages during the review period. b. Provide a timeline including: (1) When and how Kentucky Power and AEP first had discussions about coal inventory concerns during the review period in the present case. Include in the response when Kentucky Power and AEP first became aware that PJM was concerned about coal inventory levels (potential full load burn hours). (2) When and how PJM first contacted Kentucky Power about coal inventory issues during the review period in the present case. (3) When and how Kentucky Power and AEP first responded to PJM regarding coal inventory concerns during the review period through Kentucky Power's ten-day rule implementation date in the present case.

RESPONSE

a. Please refer to KPCO_R_KPSC_PHDR_1_ConfidentialAttachment1 for the requested documentation. This documentation was used for discussion purposes in monthly meetings among the Operating Company, AEPSC Commercial Operations, AEPSC Fuel Procurement and Regulatory personnel to discuss PJM energy market operations and strategy for the coming month. No meeting minutes or summaries exist.

b.1. The Company and AEP began having monthly videoconference concerning coal inventory in June 2020 and continue to hold such monthly meetings. AEP and the Company first became aware of PJM's concern with coal inventory when it received PJM's initial data request during the week of October 11, 2021. Additional information regarding PJM's data request is provided in the Company's response to subsections (b)(2) and (b)(3) below.

b.2. PJM first issued the first "Weekly Fuel Inventory and Supply Data Requests" to Kentucky Power/AEP the week of 10/11/21 to 10/17/21 using PJM's eDART communication system. The information requested were hours of run time as "economic maximum" based on current inventory, whether a site was experiencing challenges or delays in deliveries, dates of next scheduled deliveries, and how many hours of additional run time the next delivery would generate at "economic maximum". For purposes of PJM's data requests the Company used full load burn to calculate potential generation hours for "economic maximum".

b.3 AEP and the Company began providing coal inventory data to PJM in response to PJM's data request described in subsection (b)(2). AEP and the Company provided coal inventory data to PJM weekly through February 2022. After that time PJM requested that AEP and the Company provide coal inventory data on a bi-weekly basis. AEP and the Company provided coal inventory data on the requested bi-weekly basis from February 2022 through September 2022. In October 2022, PJM again requested that AEP and the Company provide coal inventory data on a weekly basis, which AEP and the Company did through February 2023, after which time PJM terminated its request for inventory data.

Witness: Kimberly K. Chilcote (subpart b.)

Witness: Alex E. Vaughan (subpart a.)

KPCO_R_KPSC_PHDR_1_ConfidentialAttachment1 has been redacted in its entirety.

Kentucky Power Company
KPSC Case No. 2023-00008
Commission Staff's Initial Post-Hearing Data Requests
Dated February 29, 2024

DATA REQUEST

KPSC PHDR_2	Refer to February 13, 2024 Hearing Testimony of Alex E. Vaughan (Hearing Video Transcript 11:37:15). a. Provide a copy of all versions of PJM Manual 13 that were in effect during the review period. b. Identify any sections of PJM Manual 13 that Kentucky Power believed applied to coal inventory levels during the review period and that Kentucky Power believes required implementation of coal conservation strategy. c. State how and when Kentucky Power and AEP responded to any changes to PJM Manual 13 regarding coal inventory requirements including documentation related to any decisions regarding its implementation. d. Identify the carrying costs associated with maintaining coal in inventory and provide the total amount of carrying costs by category during the review period.

RESPONSE

a. The requested information is publicly available at the following web address: https://pjm.com/-/media/documents/manuals/m13.ashx. The Revision History of the manual begins on page 190 of the document. The revisions noted in that section of the manual are effective dated.

b. The Company respectfully objects to this request because it seeks a legal interpretation or legal analysis, which are not the appropriate subject of discovery.

c. AEP and Kentucky Power did not immediately change their inventory requirements because of changes to PJM Manual 13. Please see the Company's response to KPSC PHDR_8 for the methodology that AEP and Kentucky Power follows annually to adjust inventory targets.

d. Utilizing month end coal inventory balances throughout the review period, the Company estimates that it reasonably and prudently incurred approximately $2 million of carrying charges associated with coal in inventory.

Witness: Kimberly K. Chilcote (subpart c.)

Witness: Alex E. Vaughan (subparts a., b., and d.)

DATA REQUEST

KPSC PHDR_3	Refer to February 13, 2024 Hearing Testimony of Kimberly K. Chilcote (Hearing Video Transcript 13:37:15). a. For the review period, identify and provide all coal contracts executed or in force, monthly deliveries received by contract along with burn projections, contract mine name and number. b. Identify and provide any coal contracts in which the supplier failed to perform during the period under review and explain the suppliers' reasons for failing to perform.

RESPONSE

a. Please refer to KPCO_R_KPSC_PHDR_3_Attachment1 for the contract in force and monthly deliveries by contract with the respective mine number and names during the review period. Additionally, please refer to KPCO_R_KPSC_PHDR_3_Attachment2 for actual burn for the review period. The testimony referenced refers to physical inventory data at the plant requested by and provided to PJM by the Company as described in the Company's response to KPSC PHDR 1(b)(2). The Company notes that the referred testimony did not reference contract-related burn projections.

b. During the review period there were several suppliers who did not perform to the obligation of their agreement. Rather than terminate the contracts and go to the market to replace the entirety of the remaining contracted amounts when coal market prices were extremely high, the Company instead chose to work with the coal suppliers that were unable to comply with their initial contract terms. The Company renegotiated the agreements with those suppliers that were unable to comply with their initial contract terms to allow for delivery over a longer period. All coal contract suppliers (with the exception of one) supplied the contracted-for amounts of coal, albeit over a longer time period than originally agreed. Additionally, for agreements that were extended outside of the review period and through March of 2024, suppliers have performed and met the obligations of the renegotiated agreements. The Company terminated one agreement during the review period due to an extended force majeure event, and financially settled another agreement due to the mine not being able to supply the coal, during the review period.

See the Direct Testimony of Kimberly K. Chilcote at page 6 lines 9 through 17 for agreement details by long-term supplier, and Kimber K. Chilcote Direct Testimony at page 7 lines 11 through 15 and page 8 lines 1 through 23 for agreement details by spot supplier.

Witness: Kimberly K. Chilcote

Kentucky Power Company
KPSC Case No. 2023-00008
Commission Staff's Initial Post-Hearing Data Requests
Dated February 29, 2024

DATA REQUEST

KPSC PHDR_4	Refer to the February 13, 2024 Hearing Testimony of Alex E. Vaughan (Hearing Video Transcript 14:20:02). a. Explain what the proprietary Power Spark software does. b. If possible, provide the equations in functional form (independent and dependent variable) and explain briefly the forecasting process used in Power Spark. c. Explain how Kentucky Power could best demonstrate how Power Spark works.

RESPONSE

a. Power Spark is the software used by the Company to calculate the energy market offer curves for generation resources that are submitted to PJM daily. The software utilizes unit specific information, quadratic equations, and calculus computations to facilitate the calculations.

b. Power Spark calculates incremental offer curves based on several levels of quadratic equations and calculus computations that are not available in spreadsheet format.

   At a high level, Power Spark calculations are as follows:

   Total Offer Costs = Fuel Cost + Handling + Chemicals + SO2 Adder + Nox Adder

   Incremental Cost ($/MWh) = Total Offer Costs * Incremental Heat Rate

   Please note that the incremental heat rate is at full load burn, or the unit's economic maximum output. The heat rate will be higher as unit output moves along the heat rate curve from economic max to economic min, resulting in differing offer prices along the offer curve.

c. A videoconference meeting with the appropriate Company personnel could be arranged to demonstrate how the Power Spark software is used to calculate energy market offer curves.

Witness: Alex E. Vaughan

Kentucky Power Company
KPSC Case No. 2023-00008
Commission Staff's Initial Post-Hearing Data Requests
Dated February 29, 2024

DATA REQUEST

KPSC PHDR_5	Refer to the February 13, 2024 Hearing Testimony of Alex E. Vaughan (Hearing Video Transcript 14:22:16). a. Provide any documents pertaining to the coal conservation adder, including but not limited to how the coal conservation adder is calculated, any documentation related to the Kentucky Power and AEP coal conservation adder committee, or PJM meeting minutes, reports, summaries, or communications. b. Provide a timetable indicating when the AEP coal conservation committee was created and when and why the committee met.

RESPONSE

a. No such ‘coal conservation committee’ exists. Rather, as discussed by Company Witness Vaughan during the hearing, there is a monthly meeting with the appropriate Operating Company, Commercial Operations, Fuel Procurement and Regulatory personnel to discuss RTO energy market operations and strategy for the coming month. Please see the Company’s response to KPSC PHDR 1 for the monthly discussion documentation.

   Please refer to Company Witness Vaughan’s Direct Testimony at page 11, line 9 through page 15, line 2 for a discussion on how the adders during the review period were determined. Additionally, the dollar figure of the adder was determined through an iterative analysis that utilized the current coal inventories, expected coal receipts, projected coal burn at forward market price estimates, unit availabilities and solved for a price adder that was expected to prevent the unit from dropping below the PJM minimum days of burn fuel requirement.

b. Generally speaking, the monthly meetings described in the response to part (a) are held the last week of each month in preparation for the next month. The meetings began in June of 2020. Please also see the Company’s response to KPSC PHDR 1.

Witness: Alex E. Vaughan

DATA REQUEST

KPSC PHDR_6	Refer to the January 9, 2024 Order of the Public Service Commission of West Virginia in Case No. 23-0377-E-ENEC entered as Staff Exhibit No. 1 in the February 13, 2024 hearing. a. Provide a copy of Post-Hearing Exhibit 2 referenced on page 9 of that Order. b. Referencing the Post-Hearing Exhibit 2, provide the same requested information solely for Kentucky Power.

RESPONSE

Kentucky Power respectfully objects to this request on the basis that it seeks information that is neither relevant to this proceeding nor reasonably calculated to lead to the discovery of admissible evidence. The information in Post-Hearing Exhibit 2 in West Virginia Case 23-0377-E-ENEC requires context not presented in that document:

- Post-Hearing Exhibit 2 in West Virginia Case 23-0377-E-ENEC provides information regarding (1) the amount of coal per day and year that would be burned at full load; (2) the amount of coal that would be burned at a 69% capacity factor (a number selected by the West Virginia Commission without sufficient record evidence); and (3) the amount of coal under contract in 2023.
- To the extent this information is used to make conclusions regarding the coal inventory that the Company should have had during the period of coal supply constraint (from October 2021 through November 2022), such conclusions would ignore the record evidence in this case (and in West Virginia Case 23-0377-E-ENEC) that coal was not readily available in the market during that period.
- To the extent this information is used to make conclusions regarding the coal inventory that the Company should store at the referenced plants at all times, such conclusions would ignore the benefits that economic dispatch of the units provide to customers.
- The Public Service Commission of West Virginia's January 9, 2024 Order in Case No. 23-0377-E-ENEC is under appeal.
- As described in the Company's response to KPSC PHDR 11, all other regulatory bodies that have reviewed the coal conservation strategy have concluded that AEP and its operating companies acted appropriately.

Subject to and without waiving these objections, the Company states as follows:

a. Please refer to KPCO_R_KPSC_PHDR_6_Attachment1 for the requested information.

b. KPCO_R_KPSC_PHDR_6_Attachment1 includes information for the Mitchell Plant. The information for Mitchell is presented on a whole-plant basis. Kentucky Power's share would be 50% of each amount provided for Mitchell.

Witness: Legal Counsel

APPALACHIAN POWER COMPANY & WHEELING POWER COMPANY WEST VIRGINIA CASE NOS. 21-0339-E-ENEC, 22-0393-E-ENEC, 23-0377-E-ENEC Commission Requested Post-Hearing Exhibits

Request No. 2

Identify how much coal would be consumed to meet a 69% capacity factor and how much coal is under contract at the Companies' plants.

Response No. 2

	Tons Per Day at Full Load Burn	Total Tons Per Year at Full Load Burn	Total Tons Per Year at 69% Capacity Factor	2023 Tons Under Contract[1]
Amos	27,348	9,982,020	6,887,594	6,483,855
Mountaineer	12,290	4,485,850	3,095,237	2,915,620
Mitchell	15,355	5,604,575	3,867,157	2,429,548

[1] Includes any contract modifications for 2023. The Companies have reduced the obligation under multiple agreements this year due to low burn and storage capacity.

Kentucky Power Company
KPSC Case No. 2023-00008
Commission Staff's Initial Post-Hearing Data Requests
Dated February 29, 2024

DATA REQUEST

KPSC PHDR_7 Refer to Kentucky Power's response to Commission Staff's Second Request for Information (Staff's Second Request), Item 2, Attachment 3.
a. Update the attachment to Identify all dates in which the offer strategy resulted in avoiding a forced outage or falling below a ten-day coal supply inventory level over the entire October 2021 through November 2022 period.
b. For dates in which a forced outage was not avoided through the offer strategy, explain whether one of both Mitchell units were dispatched despite the market price adder and whether such that no coal was conserved.

RESPONSE

a. The dates included in Staff's second request, Item 2, Attachment 3 represent the days in which a forced outage was avoided by the Company's offer strategy. There are no further updates that can be made.

b. No such dates exist because the offer strategy kept the units from being forced out due to fuel supply levels.

Witness: Kimberly K. Chilcote

Witness: Alex E. Vaughan

DATA REQUEST

KPSC PHDR_8	Refer to Kentucky Power's response to Staff's Second Request, Item 6, Attachment 2. a. Provide the calculations for annual coal inventory / full load burn and based upon those calculations, explain the decision process and what factors are considered in deciding to alter the coal inventory days. b. State if and how Kentucky Power's coal burn forecast is different than demand calculations provided in Kentucky Power's most recent Integrated Resource Plan. c. If not answered in part a, provide equations in functional form and a list of independent variables input into the modeling system to determine projected coal demand.

RESPONSE

a. Please refer to attachments KPCO_R_KPSC_PHDR_8_ConfidentialAttachment1, KPCO_R_KPSC_PHDR_8_ConfidentialAttachment2, and KPCO_R_KPSC_PHDR_8_ConfidentialAttachment3 for the annual coal inventory / full load burn calculations.

Annually, a team that includes Regulated Fuel Procurement, AEP engineering, and Company plant and management groups review the Company's coal inventory targets. During the annual review, the team determines target inventory levels adequate for the plant to operate at full load using the fuel inventory available on the plant site. The team considers items such as modes of delivery, time for delivery, and number of suppliers when establishing the inventory targets. The Company's target inventory in days of full load burn for 2020, 2021, and 2022 remained the same. In Staff's Second Request, Item 6, Attachment 2, the full load burn ending inventory days changed from December 2021 to January 2022 as a result of the heat contents used to calculate full load burn and the blend ratio for Mitchell unit 2 was changed from 60% high sulfur / 40% low sulfur to 70 high sulfur / 30 low sulfur.

b. The coal burn forecast in this filing is different from the most recent Integrated Resource Plan. The Production Costing forecast for this filing uses near-term (3 year) market forecasts to determine Net Energy Costs to the customer using existing generation, power purchase agreements, market sales, and market purchases. The Integrated Resource Plan is a long-term (30+ year) Fundamental Forecast with the objective goal of generation expansion planning.

c. The question infers that the coal burn forecast is created using some kind of linear regression model. This is not the case, and as such, equations and dependent variables cannot be provided by the Company. The coal burn forecast is created using Energy Exemplar's Plexos® market simulation model.

Witness: Kimberly K. Chilcote (subpart a.)

Witness: Mark O'Brien (subparts b. and c.)

Kentucky Power Company
KPSC Case No. 2023-00008
Commission Staff's Initial Post-Hearing Data Requests
Dated February 29, 2024

DATA REQUEST

KPSC PHDR_9	Provide the coal bid evaluation sheets by issuance date for the review periods from Case Nos. 2022-00036 and 2023-00263.

RESPONSE

Please refer to attachments KPCO_R_KPSC_PHDR_9_ConfidentialAttachment1, KPCO_R_KPSC_PHDR_9_ConfidentialAttachment2, and KPCO_R_KPSC_PHDR_9_ConfidentialAttachment3 for the requested information.

Witness: Kimberly K. Chilcote

Mitchell Low Sulfur - 2022 CAPP

May 2021 RFP Bids

Offer / Plant / Year	Mine	Quantity		Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell Low Sulfur 2022		Tons	BTU	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
[redacted]															
Argus Market 05.28.21	CAPP			$54.85	Barge	BSR	$9.64	12,000	1.67	1.00%	10.00%	$2.23	$66.72	$2.78	
[redacted]															

Mitchell	
FGD Removal Efficiency	98.00%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$113.68

Mitchell Low Sulfur - 2023 CAPP

May 2021 RFP Bids

Offer / Plant / Year	Mine	Quantity		Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell Low Sulfur 2023		Tons	BTU	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
[redacted]															
Argus Market 05.28.21	CAPP			$55.35	Barge	BSR	$10.02	12,000	1.67	1.00%	10.00%	$2.23	$67.60	$2.82	
[redacted]															

Mitchell	
FGD Removal Efficiency	98.00%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$113.68

Mitchell Low Sulfur - 2024 CAPP

May 2021 RFP Bids

Offer / Plant / Year	Mine	Quantity		Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell Low Sulfur 2024		Tons	BTU	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
[redacted]															

Mitchell	
FGD Removal Efficiency	98.00%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$113.68

Mitchell High Sulfur - 2022 NAPP

May 2021 RFP Bids

Offer / Plant / Year	Mine	Quantity		Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell High Sulfur 2022		Tons	BTU	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
[redacted]															
Argus Market 05.28.21	NAPP			$38.75	Barge	NACCO #1 - Powhatan Pt. LO, OH	$0.84	12,500	6.00	3.75%	10.00%	$8.36	$47.95	$1.92	
[redacted]															

Mitchell	
FGD Removal Efficiency	98.00%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$113.68

Mitchell High Sulfur - 2023 NAPP

May 2021 RFP Bids

Offer / Plant / Year	Mine	Quantity		Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell High Sulfur 2023		Tons	BTU	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
[redacted]															
Argus Market 05.28.21	NAPP			$39.75	Barge	NACCO #1 - Powhatan Pt. LO, OH	$0.88	12,500	6.00	3.75%	10.00%	$8.36	$48.99	$1.96	
[redacted]															

Mitchell	
FGD Removal Efficiency	98.00%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$113.68

Mitchell High Sulfur - 2024 NAPP

May 2021 RFP Bids

Offer / Plant / Year	Mine	Quantity		Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell High Sulfur 2024		Tons	BTU	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
[redacted]															

Mitchell	
FGD Removal Efficiency	98.00%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$113.68

Mitchell Low Sulfur - 2021 CAPP

September 2021

Offer / Plant / Year	Mine	Quantity	Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell Low Sulfur 2021		Tons	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
Argus Market 09.10.21	CAPP		$66.15	Barge	BSR	$9.64	12,000	1.67	1.00%	10.00%	$4.40	$80.19	$3.34	
Argus Market 09.24.21	CAPP		$70.75	Barge	BSR	$9.64	12,000	1.67	1.00%	10.00%	$4.40	$84.79	$3.53	

[redacted]

Mitchell	
FGD Removal Efficiency	98.83%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$222.26

Mitchell Low Sulfur - 2022 CAPP

September 2021

Offer / Plant / Year	Mine	Quantity	Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell Low Sulfur 2022		Tons	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
Argus Market 09.10.21	CAPP		$66.15	Barge	BSR	$9.64	12,000	1.67	1.00%	10.00%	$4.40	$80.19	$3.34	
Argus Market 09.24.21	CAPP		$70.75	Barge	BSR	$9.64	12,000	1.67	1.00%	10.00%	$4.40	$84.79	$3.53	
[redacted]														

Mitchell	
FGD Removal Efficiency	98.83%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$222.26

Mitchell Low Sulfur - 2023 CAPP

September 2021

Offer / Plant / Year	Mine	Quantity	Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell Low Sulfur 2023		Tons	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
Argus Market 09.10.21	CAPP		$64.65	Barge	BSR	$10.02	12,000	1.67	1.00%	10.00%	$4.40	$79.07	$3.29	
Argus Market 09.24.21	CAPP		$68.00	Barge	BSR	$10.02	12,000	1.67	1.00%	10.00%	$4.40	$82.42	$3.43	

[redacted]

Mitchell	
FGD Removal Efficiency	98.83%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$222.26

Mitchell Low Sulfur - 2024 CAPP

September 2021

Offer / Plant / Year	Mine	Quantity	Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell Low Sulfur 2023		Tons	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
Argus Market 09.10.21	CAPP		$64.65	Barge	BSR	$10.02	12,000	1.67	1.00%	10.00%	$4.40	$79.07	$3.29	2024 Prices not quoted yet; using 2023
Argus Market 09.24.21	CAPP		$68.00	Barge	BSR	$10.02	12,000	1.67	1.00%	10.00%	$4.40	$82.42	$3.43	2024 Prices not quoted yet; using 2023
[redacted]														

Mitchell	
FGD Removal Efficiency	98.83%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$222.26

Mitchell High Sulfur - 2021 NAPP

September 2021

Offer / Plant / Year	Mine	Quantity	Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell High Sulfur 2021		Tons	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
Argus Market 09.10.21	NAPP		$59.00	Barge	NACCO #1 - Powhatan Pt. LO, OH	$1.00	12,500	6.00	3.75%	10.00%	$16.48	$76.48	$3.06	
Argus Market 09.24.21	NAPP		$63.50	Barge	NACCO #1 - Powhatan Pt. LO, OH	$1.00	12,500	6.00	3.75%	10.00%	$16.48	$80.98	$3.24	

Mitchell	
FGD Removal Efficiency	98.83%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$222.26

Mitchell High Sulfur - 2022 NAPP

September 2021

Offer / Plant / Year	Mine	Quantity	Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell High Sulfur 2022		Tons	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
Argus Market 09.10.21	NAPP		$47.25	Barge	NACCO #1 - Powhatan Pt. LO, OH	$1.00	12,500	6.00	3.75%	10.00%	$16.48	$64.73	$2.59	
Argus Market 09.24.21	NAPP		$51.00	Barge	NACCO #1 - Powhatan Pt. LO, OH	$1.00	12,500	6.00	3.75%	10.00%	$16.48	$68.48	$2.74	

Mitchell	
FGD Removal Efficiency	98.83%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$222.26

Mitchell High Sulfur - 2023 NAPP

September 2021

Offer / Plant / Year	Mine	Quantity	Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell High Sulfur 2023		Tons	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
Argus Market 09.10.21	NAPP		$53.00	Barge	NACCO #1 - Powhatan Pt. LO, OH	$1.00	12,500	6.00	3.75%	10.00%	$16.48	$70.48	$2.82	
[redacted]														
Argus Market 09.24.21	NAPP		$56.50	Barge	NACCO #1 - Powhatan Pt. LO, OH	$1.00	12,500	6.00	3.75%	10.00%	$16.48	$73.98	$2.96	
[redacted]														

Mitchell	
FGD Removal Efficiency	98.83%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$222.26

Mitchell High Sulfur - 2024 NAPP

September 2021

Offer / Plant / Year	Mine	Quantity	Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell High Sulfur 2024		Tons	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
Argus Market 09.10.21	NAPP		$53.00	Barge	NACCO #1 - Powhatan Pt. LO, OH	$1.00	12,500	6.00	3.75%	10.00%	$16.48	$70.48	$2.82	
Argus Market 09.24.21	NAPP		$56.50	Barge	NACCO #1 - Powhatan Pt. LO, OH	$1.00	12,500	6.00	3.75%	10.00%	$16.48	$73.98	$2.96	

Mitchell	
FGD Removal Efficiency	98.83%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$222.26

Mitchell High Sulfur - 2025 NAPP

April 2022

Offer / Plant / Year	Mine	Quantity		Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell High Sulfur 2025		Tons	BTU	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
[redacted]															

Mitchell	
FGD Removal Efficiency	98.29%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$194.31

Mitchell High Sulfur - 2024 NAPP

April 2022

Offer / Plant / Year	Mine	Quantity		Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell High Sulfur 2024		Tons	BTU	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
[redacted]															
Argus 04.14.22	Pittsburgh Seam		12,500	$85.00	Barge	Ireland Dock LO - Cresap, WV	$0.91	12,500	6.00			$14.33	$100.24	$4.01	
[redacted]															

Mitchell	
FGD Removal Efficiency	98.29%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$194.31

Mitchell High Sulfur - 2023 NAPP

April 2022

Offer / Plant / Year	Mine	Quantity		Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell High Sulfur 2023		Tons	BTU	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
[redacted]															
Argus 04.14.22	Pittsburgh Seam		12,500	$90.00	Barge	Ireland Dock LO - Cresap, WV	$0.88	12,500	6.00			$14.33	$105.21	$4.21	
[redacted]															

Mitchell	
FGD Removal Efficiency	98.29%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$194.31

Mitchell High Sulfur - 2022 NAPP

April 2022

Offer / Plant / Year	Mine	Quantity		Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell High Sulfur 2022		Tons	BTU	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
Argus 04.14.22	Pittsburgh Seam		12,500	$120.00	Barge	Ireland Dock LO - Cresap, WV	$0.84	12,500	6.00			$14.33	$135.17	$5.41	

Mitchell	
FGD Removal Efficiency	98.29%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$194.31

Mitchell Low Sulfur - 2025 CAPP

April 2022

Offer / Plant / Year	Mine	Quantity		Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell Low Sulfur 2025		Tons	BTU	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
[redacted]															

Mitchell	
FGD Removal Efficiency	98.29%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$194.31

Mitchell Low Sulfur - 2024 CAPP

April 2022

Offer / Plant / Year	Mine	Quantity		Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell Low Sulfur 2024		Tons	BTU	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
Argus 04.14.22	Nymex Barge		12,000	$87.00	Barge	Mammoth Dock LO - Montgomery, WV	$9.10	12,000	1.67			$3.83	$99.93	$4.16	

[redacted]

Mitchell	
FGD Removal Efficiency	98.29%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$194.31

Mitchell Low Sulfur - 2023 CAPP

April 2022

Offer / Plant / Year	Mine	Quantity		Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell Low Sulfur 2023		Tons	BTU	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
Argus 04.14.22	Nymex Barge		12,000	$96.00	Barge	Mammoth Dock LO - Montgomery, WV	$8.75	12,000	1.67			$3.83	$108.58	$4.52	
[redacted]															

Mitchell	
FGD Removal Efficiency	98.29%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$194.31

Mitchell Low Sulfur - 2022 CAPP

April 2022

Offer / Plant / Year	Mine	Quantity		Coal Price	Transportation			Offered Quality				Quality Adjusted Delivered Pricing			
Mitchell Low Sulfur 2022		Tons	BTU	Coal Price	River / Rail	MP / District	Rate	Btu	lbs. SO_2	Sulfur %	Ash %	Quality Adj.	Quality Adjusted Delivered Cost	Delivered $MMBTU	Comments
[redacted]															
Argus 04.14.22	Nymex Barge		12,000	$126.00	Barge	Mammoth Dock LO - Montgomery, WV	$8.41	12,000	1.67			$3.83	$138.24	$5.76	
[redacted]															

Mitchell	
FGD Removal Efficiency	98.29%
SO_2 Allowance Cost	$1.50
Removal Cost $/Ton	$194.31

Kentucky Power Company
KPSC Case No. 2023-00008
Commission Staff's Initial Post-Hearing Data Requests
Dated February 29, 2024

DATA REQUEST

KPSC PHDR_10	State whether Kentucky Power factors in expected revenue from sales of coal byproducts such as ash or gypsum when preparing coal bid solicitation evaluations. Provide the revenue amounts for any coal post combustion byproducts sold during the review period.

RESPONSE

No, Kentucky Power does not factor in the sale of coal byproducts while evaluating coal bids.

Witness: Kimberly K. Chilcote

DATA REQUEST

KPSC PHDR_11	Provide a copy of any orders from other states that have reviewed AEP's operating company's coal conservation programs.

RESPONSE

The Company's affiliate Indiana Michigan Power Company has received orders in Indiana fuel cases, and Appalachian Power Company has been audited by FERC Staff, and the Virginia State Corporation Commission during the time period in question. None of these regulatory bodies have made any findings of imprudence in regards to the Companies' fuel procurement or energy market offer process and/or practices.

Please see KPCO_R_KPSC_PHDR_11_Attachment1 for the requested information.

Witness: Alex E Vaughan

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. FA22-1-000
March 15, 2024

Appalachian Power Company
Attention: Kate Sturgess
Senior Vice President, Controller and
Chief Accounting Officer
1 Riverside Plaza
Columbus, OH 43215

Dear Ms. Sturgess:

1. The Division of Audits and Accounting (DAA) within the Office of Enforcement (OE) of the Federal Energy Regulatory Commission (Commission or FERC) has completed an audit of Appalachian Power Company (APCo or the Company). The audit covered the period January 1, 2019 to June 30, 2023.

2. The audit evaluated APCo's compliance with: (1) its Commission-approved fuel-adjustment clauses (FAC) and formula rate or tariff recovery mechanisms used to recover fuel and purchased-power costs in billings to wholesale customers; and (2) accounting regulations in the Uniform System of Accounts Prescribed for Public Utilities and Licensees under 18 C.F.R. Part 101 related to fuel and purchased-power costs. The enclosed audit report contains four findings and 18 recommendations that require APCo to take corrective action.

3. On February 26, 2024, APCo notified DAA that APCo accepts the four findings and agrees to implement the 18 recommendations. A verbatim copy of APCo's response is included as Section V of the accompanying audit report. I hereby approve the audit report.

4. APCo should submit its implementation plan to comply with the recommendations within 30 days of issuance of this letter order. APCo should make quarterly submissions to DAA describing the progress made to comply with the recommendations, including the completion date for each corrective action. As directed by the audit report, these submissions should be made no later than 30 days after the end of each calendar quarter, beginning with the first quarter after this audit report is issued, and continuing until all the corrective actions are completed.

5. The Commission delegated authority to act on this matter to the Director of OE under 18 C.F.R. § 375.311. This letter order constitutes final agency action with respect to all uncontested findings and recommendations. APCo may file a request for rehearing of this letter order with the Commission within 30 days of the date of this order under 18 C.F.R. § 385.713.

6. This letter order is without prejudice to the Commission's right to require hereafter any adjustments it may consider proper from additional information that may come to its attention. In addition, any instance of non-compliance not addressed herein or that may occur in the future may also be subject to investigation and appropriate remedies.

7. I appreciate the courtesies extended to the auditors. If you have any questions, please contact Ms. Kristen Fleet, Director and Chief Accountant, Division of Audits and Accounting at (202) 502-8063.

Sincerely,

Janel Burdick
Director
Office of Enforcement

Enclosure

Federal Energy Regulatory Commission
Office of Enforcement
Division of Audits and Accounting

AUDIT REPORT

Audit of Appalachian Power Company's compliance with:

- Its Commission-approved fuel-adjustment clauses (FAC) and formula rate or tariff recovery mechanisms used to recover fuel and purchased-power costs in billings to wholesale customers; and

- Accounting requirements of the Uniform System of Accounts Prescribed for Public Utilities and Licensees under 18 C.F.R. Part 101 related to fuel and purchased-power costs.

Docket No. FA22-1-000
March 15, 2024

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I. Executive Summary

A. Overview

The Division of Audits and Accounting (DAA) in the Office of Enforcement of the Federal Energy Regulatory Commission (Commission or FERC) has completed an audit of Appalachian Power Company (APCo or the Company). The audit evaluated APCo's compliance with: (1) its Commission-approved fuel-adjustment clauses (FAC) and formula rate or tariff recovery mechanisms used to recover fuel and purchased-power costs in billings to wholesale customers; and (2) accounting regulations in the Uniform System of Accounts Prescribed for Public Utilities and Licensees under 18 C.F.R. Part 101 related to fuel and purchased-power costs. The audit covered the period from January 1, 2019 to June 30, 2023.

B. Appalachian Power Company

APCo is a subsidiary of American Electric Power Company, Inc. (AEP), a public utility holding company based in Columbus, Ohio. APCo is an operating utility engaged in the generation, transmission, and distribution of electricity to approximately 964,000 customers in southwestern Virginia and southern West Virginia. APCo also supplies and markets wholesale power to electric utilities, municipalities, and other market participants. Wholesale customers served by APCo (i.e., those purchasing electricity for resale) comprised approximately 15% percent of APCo's total megawatt-hour sales in 2022. The Company owns approximately 6,512 MW of generating capacity, 6,339 miles of transmission lines, and 55,134 miles of distribution lines, and has 1,650 employees. APCo is a member of PJM Interconnection, L.L.C. (PJM), and its transmission service charges are derived through a formula rate in Attachment H-14 of the PJM Open Access Transmission Tariff (OATT).

C. Summary of Compliance Findings

Audit staff identified four findings of noncompliance. Below is a summary of audit staff's compliance findings. Details are in Section IV of this report.

1. *Amortization of Retail Regulatory Assets* – APCo improperly included the amortization of certain regulatory assets arising from state-jurisdictional rate adjustment clauses in Account 501, Fuel Expense, as an input to the Company's cost-based formula rates without Commission approval.

2. *Classification of Purchased Power Costs* – APCo improperly included approximately $7,606,000 of non-energy costs in the purchased power component of FAC calculations from 2019 to 2021, in which only energy-related economic

purchases should be included. As a result, certain FERC-jurisdictional wholesale customers were overcharged by approximately $490,000.

3. *Fly Ash Sales Revenue and Expense* – APCo did not exclude the expenses incurred in connection with fly ash sales for beneficial reuse from its wholesale cost-based fuel recovery formulas. By not excluding fly ash sales-related costs as required by its wholesale Requirements Service formulas, APCo overstated its revenue requirement by approximately $178,000.

4. *FERC Form No. 580 Reporting* – APCo did not properly follow the FERC Form No. 580 instructions and, therefore, did not report all required information in its FERC Form No. 580 filings. These actions affected the transparency, accuracy, and usefulness of certain sections of the FERC Form No. 580.

D. List of Recommendations

This section lists audit staff's recommendations to remedy this report's four findings on noncompliance. Audit staff's 18 compliance recommendations are listed below and repeated in Section IV after the specific finding to which they relate. To address the areas of noncompliance, audit staff recommends that APCo:

Amortization of Retail Regulatory Assets

1. Revise policies and procedures regarding regulatory asset cost recovery to ensure that wholesale customers are held harmless of state-jurisdictional rate design except if authorized by the Commission.

2. Provide training to staff on the policies and procedures and conduct training regarding regulatory asset cost recovery to ensure that wholesale customers are held harmless of state-jurisdictional rate design except if authorized by the Commission. Also, develop a training program that supports the provision of periodic training in this area, as needed.

3. Cease any further impact to FERC-jurisdictional customers from state commission orders and rate adjustment clauses or, within 120 days of the issuance of this report, file to obtain Commission approval for the recovery of this regulatory asset through a separate section 205 application to the Commission requesting such recovery.

Classification of Purchased Power Costs

4. Revise policies and procedures to ensure that purchased power costs are appropriately classified between energy-related and demand-related categories of purchases.

5. Train relevant staff on the revised policies and procedures and provide periodic training in this area, as needed.

6. Perform an analysis, and submit it to DAA for review, of the impact of misclassified purchased power costs on wholesale billings during the audit period, based on APCo's tariffs filed with the Commission, within 60 days of issuance of this audit report.

7. Submit a refund analysis, if applicable, within 60 days of issuance of this audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries during the audit period that resulted from the misclassified purchased power costs as identified pursuant to the analysis performed in response to Recommendation No. 6, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to receive refunds; and (5) period(s) for which refunds will be made.

8. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

9. Refund the amounts disclosed in the refund report to customers, with interest calculated in accordance with section 35.19a of the Commission's regulations.

Fly Ash Sales Revenue and Expense

10. Revise policies and procedures to ensure that all costs relating to fly ash sales are properly tracked and excluded from wholesale Requirements Service formulas.

11. Train relevant staff on the revised policies and procedures and provide periodic training in this area, as needed.

12. Perform an analysis, and submit it to DAA for review, of the impact of improper tracking of fly ash sales-related costs on wholesale billings during the audit period, based on APCo's tariffs filed with the Commission, within 60 days of issuance of this audit report.

13. Submit a refund analysis, if applicable, within 60 days of issuance of this audit report, to DAA for review that explains and details the following: (1) calculation

of refunds that include the amount of inappropriate recoveries during the audit period that resulted from the improper tracking of fly ash sales-related costs as identified pursuant to the analysis performed in response to Recommendation No. 12, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to receive refunds; and (5) period(s) for which refunds will be made.

14. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

15. Refund the amounts disclosed in the refund report to customers, with interest calculated in accordance with section 35.19a of the Commission's regulations.

FERC Form No. 580 Reporting

16. Revise policies and procedures regarding FERC Form No. 580 reporting of tariffs, power purchases, and fuel supply contracts to ensure that complete and accurate information is reported in accordance with the Commission's instructions in FERC Form No. 580.

17. Provide training for relevant personnel to ensure that FERC Form No. 580 reporting policies and procedures, as revised, are complied with.

18. Refile the FERC Form No. 580 for the 2018-19 and 2020-21 reporting periods to provide complete and accurate responses to Questions 2, 3, and 6 as discussed in the body of this finding.

E. Implementation of Recommendations

Audit staff further recommends that APCo submit the following for audit staff's review:

- A plan for implementing the recommendations within 30 days after the final audit report is issued;

- Quarterly reports describing progress in completing each corrective action recommended in the final audit report. Quarterly nonpublic submissions should be made no later than 30 days after the end of each calendar quarter, beginning with the first quarter after the audit report is issued and continuing until all recommended corrective actions are completed; and

- Copies of any written policies and procedures developed in response to recommendations in the audit report. These documents should be submitted in the first quarterly filing after completion of such policies and procedures.

II. Background

A. Cost-Based Fuel Recovery Mechanisms

The Commission has approved rates for electric service that usually contain two components: a demand charge to recover a utility's fixed (capacity-related) costs and an energy charge to recover a utility's variable costs, primarily for fuel. The energy charge is divided into two components. The first is the "basic energy rate," which recovers the "base cost" of fuel and other energy-related costs. The Commission must approve in advance the basic energy rate. The second element is the fuel adjustment clause (FAC). This charge is an automatic adjustment clause and is based on a formula designed to recover the difference (plus or minus) between the base cost of fuel and the actual cost of fuel incurred over time. The Commission must approve a utility's FAC formula because it is part of a utility's filed rate. Since the FAC is approved by the Commission, the monthly charge from application of the formula need not be filed with the Commission for approval. This enables utilities to keep their rates in line with current fuel costs without continually having to file for rate increases and decreases.

Consistent with its authority to approve automatic adjustment clauses under the Federal Power Act,[1] the Commission has also granted many utilities approval to offer wholesale electricity service using rates determined by cost-of-service formulas for not just fuel and purchased power, but also for the costs that would otherwise have been set in a base rate case for energy and demand rates (collectively, wholesale cost-based formula rates). Through an annual update process that incorporates newly disclosed FERC Form No. 1 financial data, such wholesale formula rates can change annually, or even more frequently, if the Commission's approval allows such frequency.

During the audit period, APCo had three wholesale customers for whom it provided full- or partial-requirements service of electricity at cost-based rates: (1) Kingsport Power Company, an affiliate of APCo; (2) Musser Companies;[2] and (3) Virginia Tech. The service agreement with Kingsport Power Company included only formula-based rate mechanisms limited to certain fuel and purchased power costs, while the agreements with Musser Companies and Virginia Tech included wholesale formula rates as described above. APCo's most recent service agreements with these customers became effective January 1, 2009, January 1, 2010, and January 1, 2010, respectively.

[1] *See* 16 U.S.C. § 824d(f).

[2] The Musser Companies consist of Black Diamond Power Company, Elk Power Company, Elkhorn Public Service Company, Kimball Light and Water Company, Union Power Company, United Light and Power Company, and War Light and Power Company.

Effective May 31, 2019, APCo terminated its cost-based service agreement with Virginia Tech. In addition to these customers, which were served under filed Rate Schedules, APCo also served five customers during the audit period using service agreements subject to its Commission-approved Market-Based Rate (MBR) tariff.[3] The service agreements related to these five customers were reported as formula-based rate mechanisms in the FERC Electric Quarterly Reports (EQRs) submitted by APCo, but, due to the reporting exemptions available to entities who offer service agreements under an MBR tariff, the details of these formula rate service agreements are not contained in FERC's eTariff system. Although these MBR service agreements use a formulaic computation as part of determination of their rates, the final rates settled on between APCo and its customers may differ from the formulaic results if so negotiated. Nevertheless, the formulaic computation, which could include inputs from APCo's FERC Form No. 1, may be impacted based on the accuracy of the Company's FERC Form No. 1 reporting as well as other factors agreed upon between the customer and the company.

B. Purchased Power & Economic Dispatch

As a member of PJM, APCo offers its generating resources into the day-ahead and real-time markets organized by PJM. APCo likewise bids for expected and actual demand due to its load obligations in these same PJM markets. APCo's resources that clear the day-ahead or real-time market are committed based on PJM's dispatching instructions. Depending on the available capacity of its own generation resources, APCo sometimes supplies more power to PJM than its own load obligations demand, while at other times APCo must purchase power from PJM to meet its own load obligations. A net-export condition therefore results in "off-system sales" revenues, while a net-import condition results in purchased power expenses.

APCo is also party to numerous power purchase agreements (PPAs), as reflected in its filings with the Commission. The resources associated with these PPAs vary in nature, with some being variable and dispatchable, while others are fixed and non-dispatchable. The non-dispatchable PPAs are primarily non-pumped hydropower, wind, and solar facilities. APCo offers the expected output of these resources into PJM and settles the actual operational output bilaterally with its PPA counterparties.

FERC's regulations governing tariffs with FACs require that, if purchased power is included in the inputs to the formula calculating the automatic adjustment clause, it

[3] The original four customers at the beginning of this audit period were Craig-Botetourt Electric Cooperative, Inc.; City of Radford, VA; City of Salem, VA; and Old Dominion Electric Cooperative. Virginia Tech became the fifth customer when it terminated its cost-based service agreement and began service through an MBR-based service agreement.

must be at a cost to the customers no greater than the variable cost that otherwise would have been incurred in dispatching the utility's own generation resources (the avoided variable cost rule).[4]

To comply with the terms of its wholesale FERC-jurisdictional FAC service agreements (subject to 18 C.F.R. § 35.14) and state regulatory requirements, APCo performs a monthly analysis to separately assign supply costs between its different types of load obligation. APCo refers to this analysis as "cost reconstruction" because its purpose is to reconstruct resource costs on an economic dispatch basis such that off-system sales are served by the highest cost resources first, while native load sales are served by the remaining, lower cost resources. This algorithmic approach mirrors unit commitment and economic dispatch (UCED) modeling but is distinct from the unit commitment process governed by PJM operations.

The cost reconstruction process occurs in a system called PowerTracker. The system uses inputs from engineering data sources to determine thermal resource variable cost curves (expressed in $/MMBTU), commodity market data sources for other fuel and energy cost variables, PJM data sources for locational marginal pricing and actual dispatch conditions, and operational data sources to validate supply and demand of energy during each operating hour. Cost reconstruction calculations are performed for each operating hour of the month to assign the resources with highest variable cost to any off-system sales load. After subtracting the load and resources relating to off-system sales, the remaining load and resources are assigned to APCo's native load in order to calculate the component of purchased power costs that are assigned to native load customers such as those served under FERC-jurisdictional FAC service agreements.

C. Fuel Supply Contracts

To ensure adequate supply of fossil-based fuels and necessary reagents, APCo enters into both short-term and long-term purchase contracts with various fuel suppliers. APCo does not own natural gas storage facilities but, rather, contracts for firm- and interruptible-delivery with various natural gas pipelines that serve its gas-fired generation facilities. APCo likewise does not maintain any coal storage facilities other than on-site stockpiles, instead relying on supply contracts for short- and long-term requirements. These contracts generally include terms and conditions that penalize both supply shortfalls (i.e., the supplier failing to deliver contracted amounts) and demand shortfalls (i.e., APCo failing to accept delivery of contracted amounts). Shortfall costs, as well as consideration paid for a de-obligation of certain delivery amounts ("buy-down" or "buy-out" agreements), must both be reported on FERC Form No. 580 and can only be

[4] 18 C.F.R. § 35.14(a)(2)(iv) and (a)(12).

collected through FAC service agreements if agreed to in the service agreement(s) or subsequently authorized by the Commission.

III. Audit Objectives, Scope, and Methodology

A. Audit Objectives

The audit evaluated APCo's compliance with: (1) its Commission-approved FAC and formula rate or tariff recovery mechanisms used to recover fuel and purchased-power costs in billings to wholesale customers; and (2) accounting regulations in the Uniform System of Accounts Prescribed for Public Utilities under 18 C.F.R. Part 101 related to fuel and purchased-power costs. The audit covered the period from January 1, 2019 to June 30, 2023.

B. Audit Scope and Methodology

Audit staff performed the following actions to facilitate the testing and evaluation of APCo's compliance with Commission requirements relevant to the audit objectives:

Audit Planning, Processes, and Administration

Audit staff performed these actions to identify audit risks and plan the audit field work:

- *Reviewed Public Information* – Reviewed publicly available information relating to APCo's operations, structure, history, regulatory oversight, tariff, and other pertinent business and regulatory aspects prior to commencing the audit on March 30, 2022. Some of the materials reviewed included APCo's FERC Form No. 1s and FERC Form No. 580s, AEP's SEC Form 10-Ks, Commission filings and orders, APCo's tariff, APCo's and AEP's corporate websites, and trade press and news articles.

- *Identified Regulatory Standards and Audit Criteria* – Identified regulatory requirements and criteria with which to evaluate APCo's compliance with audit objectives, including the rates, terms, and conditions in its wholesale FAC, Commission accounting and reporting requirements in 18 C.F.R. Parts 101 and 141, and other Commission rules, regulations, and orders generally applicable for jurisdictional public utilities.

- *Data Collection and Data Requests* – Issued formal data requests for information and audit evidence, including APCo's internal policies and procedures, financial accounting and transactional data, support for and disclosures in APCo's FERC filings, internal and external audit reports, corporate compliance program procedures, and other items not publicly available. These data were used to evaluate APCo's compliance with Commission requirements relevant to the audit's objectives.

- *Conducted Teleconference Interviews* – Conducted multiple teleconferences with APCo employees to discuss audit objectives, processes, procedures and operations, testing, data request responses, technical and administrative matters, and compliance concerns.

- *Conducted Virtual Site Visit* – Conducted a virtual site visit to discuss, observe, and evaluate APCo's procedures, practices, and controls for ensuring compliance with the Commission's regulations. The visit enabled audit staff to:

    - Discuss APCo's corporate structure, departmental functions, and employee responsibilities, and meet with key company officials;

    - Learn about APCo's generation and operations, in particular the assets, departments, activities, functions, systems, and processes used;

    - Interview executives, managers, and staff responsible for accounting, financial reporting, generation operations, and corporate compliance;

    - Discuss management and operation of APCo's corporate compliance program; and

    - Discuss and observe accounting and reporting procedures, processes, and controls relevant to audit scope.

<u>Compliance with Commission Accounting Regulations and APCo's Cost-Based Rate Mechanisms for Fuel and Purchased Power Costs (including its FAC)</u>

Audit staff also performed specific tests and evaluations of APCo's compliance with its tariff, rates, and accounting and reporting requirements. Below are the more significant areas evaluated:

- *Evaluated Cost-Based Rate Processes and Procedures* – Audit staff evaluated APCo's FERC Form No. 580 FAC processes, procedures, and quality controls to determine whether the recovery of fuel and purchased power costs from wholesale customers through the Commission-approved recovery mechanism complied with APCo's FERC-approved wholesale cost-based formulas (including its FAC) and applicable Commission accounting and other regulations.

- *Fuel and Power Cost Recovery* – Assessed APCo's recovery of fuel and purchased power costs from wholesale customers. As part of this review, audit staff selected a sample from APCo's general ledger and verified the accuracy of the wholesale cost-based formula calculations. Audit staff performed the following fuel and cost recovery testing:

    - Reviewed APCo's fuel procurement policies and procedures, its selection of fuel suppliers, and the cost of fuel and energy purchases;

    - Analyzed the cost of fuel on hand included in the wholesale cost-based formula calculations by obtaining supporting invoices and journal entries for costs recorded in Account 151, Fuel Stock. Compared the costs recorded in APCo's general ledger to the costs of fuel on hand in cost input calculations for the sample to ensure that amounts passed through the wholesale cost-based formulas were properly recorded in Account 151 and were allowable under the Commission's regulations. Also, reviewed supplier invoices to verify the accuracy of the amounts recorded in Account 151;

    - Evaluated purchased power expenses in the wholesale cost-based formula calculations, and then reviewed supporting invoices for select purchases for the sample and tied these amounts to those booked to Account 555, Purchased Power, in APCo's general ledger. Also, interviewed APCo employees and reviewed supporting material to ensure that amounts in the wholesale cost-based formulas pertained exclusively to energy-related economic purchases;

    - Analyzed costs recorded in Accounts 501, Fuel, and 547, Fuel, by reviewing supporting documentation, such as worksheets and journal entries, for the sample to determine the items APCo included in its wholesale cost-based formula calculations. Also, interviewed APCo employees to clarify worksheet information and journal entries;

    - Compared the unit rate calculated under APCo's wholesale fuel protocols to customer invoices to verify that APCo charged customers the appropriate unit rate;

    - Interviewed APCo staff to understand how APCo computed its wholesale cost-based formula rate adjustments; and

    - Tested the accuracy of APCo's calculation of its billings by comparing how APCo calculated its billings to the formula outlined in APCo's wholesale service agreements.

IV. Findings and Recommendations

1. Amortization of Retail Regulatory Assets

APCo improperly included the amortization of certain regulatory assets arising from state-jurisdictional rate adjustment clauses in Account 501, Fuel Expense, as an input to the Company's cost-based formula rates without Commission approval.

Pertinent Guidance

- 18 C.F.R. § 35.1(e) states:

> No public utility shall, directly or indirectly, demand, charge, collect or receive any rate, charge or compensation for or in connection with electric service subject to the jurisdiction of the Commission, or impose any classification, practice, rule, regulation or contract with respect thereto, which is different from that provided in a rate schedule required to be on file with this Commission unless otherwise specifically provided by order of the Commission for good cause shown.

- 18 C.F.R. § 35.13(a)(2)(i)(E) states:

> If the utility models its filing in whole or in part on retail rate decisions or settlements, the utility must provide detailed calculations and a narrative statement showing how all retail rate treatments are factored into the cost of service.

- 18 C.F.R. Part 101, Account 182.3, Other Regulatory Assets, states in part:

> B. The amounts included in this account are to be established by those charges which would have been included in net income, or accumulated other comprehensive income, determinations in the current period under the general requirements of the Uniform System of Accounts but for it being probable that such items will be included in a different period(s) for purposes of developing rates that the utility is authorized to charge for its utility services. When specific identification of the particular source of a regulatory asset cannot be made, such as in plant phase-ins, rate moderation plans, or rate levelization plans, account 407.4, regulatory credits, shall be credited. The amounts recorded in this account are generally to be charged, concurrently with the recovery of the amounts in rates, to the same account that would have been charged if included in

> income when incurred, except all regulatory assets established through the use of account 407.4 shall be charged to account 407.3, regulatory debits, concurrent with the recovery in rates.

- In *Piedmont Municipal Power Agency*, the Commission stated in relevant part:

> [A]pproval for accounting purposes does not constitute approval for ratemaking purposes. Moreover, we are not bound by state commission decisions when examining wholesale rates. For a regulatory asset to be included and recovered in Commission-jurisdictional rates, we must be allowed to determine that the charges are just and reasonable. Since we have exclusive jurisdiction over wholesale sales, it is not enough to have state approval for recovery of costs when the costs include both wholesale and retail amounts. DEC may have the discretion to record a regulatory asset in Account 182.3 based upon those state orders, but the criteria of "probable" recovery does not guarantee recovery with respect to transmission and wholesale rates; for that, Commission approval is necessary.[5]

- In *Ameren Corp.,* the Commission stated in relevant part:

> The Commission has explained that, "in approving any formula rate, the Commission approves the formula itself, the algebraic equation used to calculate the rates. It does not approve the inputs into the formula or the charges resulting from the application of the inputs to the algebraic equation."[6]

- In *PJM Interconnection, L.L.C. and Virginia Electric and Power Co.,* the Commission held in 2005 that any party desiring to recover claimed costs in a period other than the period in which they would ordinarily be charged must submit a filing with the Commission seeking approval of such recovery:

> [W]e [have] provided guidance applicable to any transmission owner seeking to recover a regulatory asset in its rates. We [have] stated, for example, that our accounting rules require "a utility to recognize a regulatory asset where it [the utility] determines it is probable that a cost that would otherwise be charged to expense in one period will

[5] *Piedmont Mun. Power Agency,* 162 FERC ¶ 61,109, at P 32 (2018).

[6] *Ameren Corp.,* 147 FERC ¶ 61,225, at P 27 (2014) (footnotes omitted) (quoting *Am. Elec. Power Serv. Corp.,* 124 FERC ¶ 61,306, at P 34 (2008)).

> be recovered in rates in another." We [have] also stated that "any party desiring to recover [its claimed costs] in rates other than [in] the period in which they would ordinarily be charged to expense must submit a filing demonstrating that their retail rates in effect applicable to that period [do not or will not permit recovery of those costs in that period] and a rate plan for recovery of them in a different period."[7]

- In *Midwest Independent Transmission System Operator, Inc.*, the Commission stated, in 2004, that the regulatory asset approach includes a filing demonstrating that retail rates will not permit recovery of certain identified costs in the ordinary period, and including a "rate plan for recovery" of such costs in a different period:

> With regard to the regulatory asset approach, as the Commission has stated in previous orders, the Commission will continue to apply the existing standard as set forth in 18 C.F.R. Part 101, Account No. 182.3 (2003).
>
> In general, this standard requires a utility to recognize a regulatory asset where it determines it is probable that a cost that would otherwise be charged to expense in one period will be recovered in rates in another. Accordingly, any party desiring to recover the Schedule 16 and 17 charges [at issue in this proceeding] in rates other than [in] the period in which they would ordinarily be charged to expense must submit a filing demonstrating that their retail rates in effect applicable to that period do not or will not permit recovery of those costs in that period and a rate plan for recovery of them in a different period.[8]

Background

APCo provides electric services to customers in multiple state jurisdictions, primarily in West Virginia and Virginia. Due to the ratemaking actions of these state jurisdictions, APCo received approvals from the state jurisdictions to defer certain costs

[7] *PJM Interconnection, L.L.C. and Va. Elec. and Power Co.,* 110 FERC ¶ 61,234, at P 41 (2005) (footnotes omitted) (quoting*, respectively*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,337, at P 13 (2004); *id.* P 15), *pet. for rev. dismissed sub nom. Va. State Corp. Comm'n v. FERC*, 468 F.3d 845 (D.C. Cir. 2006).

[8] *Midwest Indep. Transmission Sys. Operator*, *Inc.*, 106 FERC ¶ 61,337, at PP 14-15 (2004) (footnotes and paragraph number omitted).

related to fuel and purchased power expenses as regulatory assets and recover the retail portion of those costs in retail rates. Audit staff reviewed the costs recorded as regulatory assets to determine whether the costs were appropriately accounted for and approved by the Commission for inclusion in APCo's cost-based rate mechanisms (including its FAC) and recovery from wholesale customers.

Audit staff found that APCo recorded several of these regulatory assets related to fuel, purchased power costs, and other fuel-related activities in Account 182.3. APCo also amortized these regulatory assets over the period authorized by the retail regulators. Many of these amortized costs were included in Account 501, Account 555, and other accounts that are inputs to APCo's wholesale fuel and purchased power cost formulas. However, APCo did not seek Commission approval to recover any portion of the retail regulatory assets through its wholesale fuel and purchased power cost formulas.

Retail Jurisdictional Fuel Deferrals

In 2007 and 2006, respectively, the Virginia and West Virginia state regulatory commissions instituted deferred fuel and purchased power expense tracking mechanisms, which set initial fuel and purchased power rates separately from APCo's base rates.[9] Pursuant to this structure, APCo separately tracked its actual fuel and purchased power expenses and applied annually in each state for an update to its fuel and purchased power rate, either to decrease it in response to decreasing fuel and purchased power costs or to increase it in response to increasing fuel and purchased power costs. The fuel and purchased power rates are calculated using apportionment factors for each jurisdiction, and deferred cost amounts are credited against or debited to Account 501 and Account 555—as inputs to APCo's wholesale fuel and purchased power cost formulas—in proportion to the over- or under-collections determined by the retail-jurisdictional apportionments.

APCo's deferred fuel balances decreased from $97 million in January 2019 to less than $1 million by November 2020. This decrease was caused by the over-collection of fuel and purchased power costs from its retail customers during that period. Subsequently, the deferred fuel balances increased to almost $200 million by December 2021 and almost $700 million by December 2022. This increase was caused by the under-collection of fuel and purchased power costs from APCo's retail customers. APCo recognized the deferral adjustments in accounts that flow through its wholesale cost formulas, and therefore these retail rate actions affected wholesale customers' rates,

[9] *See* Code of Virginia § 56-249.6.B (codifying annual fuel clause proceedings); West Virginia Public Service Commission, Case No. 05-1278-E-PC-PW-42T (initiating requirement for Expanded Net Energy Cost proceedings).

which differed from what they would have been charged absent retail fuel deferral accounting.

According to billing details reviewed by audit staff, APCo's wholesale customers have been impacted by this retail fuel deferral accounting since APCo began using deferral mechanisms in Virginia and West Virginia. However, nothing in APCo's wholesale tariffs requires APCo to provide wholesale customers this rate parity, nor explicitly protects the customers' right to claim it. Moreover, because the proceedings that govern these deferral mechanisms were at the retail level, APCo's wholesale customers have no presumptive right to intervene in those retail proceedings to represent their own interests on the record.

Virginia Rider E-RAC

During the audit period, Virginia's State Corporation Commission (SCC) approved an additional rate adjustment clause known as E-RAC. APCo applied for E-RAC to separately track and "recover on a timely basis its projected costs to comply with state and federal environmental laws and regulations applicable to generation facilities used to serve" APCo's load.[10] The SCC approved an initial revenue requirement of approximately $27.4 million corresponding to the Virginia retail portion of APCo's approved capital and O&M costs. As with most retail rate adjustment clauses, this enabled APCo to collect through retail rates costs that would otherwise have gone unrecovered until new base rates were approved. In 2022, APCo deferred an additional $6.9 million, including an AFUDC component of $3.4 million.

APCo implemented the SCC's order by crediting the full SCC-approved amount from Account 501, Fuel, and debiting the newly created regulatory asset subaccount in Account 182.3 and subsequently amortized it back to Account 501. Because Account 501 flows through to APCo's wholesale formula rate, the deferral and amortization of the Virginia E-RAC rider impacted FERC-jurisdictional wholesale rates similarly to the way in which E-RAC rider impacted retail-jurisdictional rates.

Summary

Audit staff determined that the regulatory assets discussed above were not approved by the Commission for recovery in FERC-jurisdictional rates. The

[10] *See* State Corporation Commission, *Order Granting Rate Adjustment Clause*, Case No. PUR-2020-00258 (2020), p. 1.

Commission has stated, in Order No. 552[11] and subsequent orders, that any party desiring to recover expenses in rates outside the period in which they would ordinarily be charged must receive approval to recover the deferred cost and approval of the amortization period for recovery.[12] Such a required filing is not a mere formality; it is a necessary step

[11] *Revisions to Unif. Sys. Of Accts. To Account for Allowances under the Clean Air Act Amends. Of 1990 & Regulatory-Created Assets & Liabilities & to Form Nos. 1, 1-F, 2 and 2-A*, Order No. 552, 58 Fed. Reg. 17982 (Apr. 7, 1993), FERC Stats. & Regs. ¶ 30,967 (1993) (cross-referenced at 62 FERC ¶ 61,299).

[12] *See, e.g., PJM Interconnection, L.L.C. and Va. Elec. and Power Co.,* 110 FERC ¶ 61,234 at P 41 ("any party desiring to recover" a regulatory asset "must submit a filing demonstrating that their retail rates in effect applicable to that period" will not permit recovery of the costs in the normal period and submit "a rate plan for recovery of them in a different period."); *Midwest Indep. Transmission Sys. Operator, Inc*., 106 FERC ¶ 61,337 at P 15 ("any party desiring to recover the Schedule 16 and 17 charges in rates other than [in] the period in which they would ordinarily be charged to expense must submit a filing."); *Midwest Indep. Transmission Sys. Operator, Inc*., Order on Petition for Declaratory Order, 102 FERC ¶ 61,279, at P 1 (2003) ("We find that Midwest ISO's load serving stakeholders may make a rate filing with the Commission clearly demonstrating and supporting that any such costs are currently unrecoverable and so should be treated as a regulatory asset.") (citation omitted), *reh'g denied, clarification provided*, 106 FERC ¶ 61,337 (2004); *id.* P 15 ("Midwest ISO TOs may file pursuant to [FPA] Sections 205 or 206, as appropriate, with the Commission, in the event that they cannot otherwise recover the Schedule 10 costs charged to them, a request for rate recovery of such costs as a regulatory asset.") (footnote omitted); *id.* ("load serving stakeholders are entitled to the same opportunity to make a rate filing with the Commission clearly demonstrating and supporting that the Schedule 16 and 17 costs are currently unrecoverable and should be treated as a regulatory asset under . . . Account No. 182.3"); *Midwest Indep. Transmission Sys. Operator, Inc*., 102 FERC ¶ 61,192, at P 30 (2003) ("we will permit . . . parties, at their discretion, to make a filing with the Commission clearly demonstrating and supporting that such costs [ISO Cost Adder charges] are indeed currently unrecoverable and should be treated as a regulatory asset under the Commission's Uniform System of Accounts properly classified in Account No. 182.3, Other Regulatory Assets."), *reh'g denied, clarification provided,* 104 FERC ¶ 61,012, at P 29 (2003) ("With respect to the Kentucky Commission concern as to the standard to review rate filings for regulatory asset treatment, we clarify that we will continue to apply the existing standard as set forth in 18 C.F.R. Part 101, Account No. 182.3 (2002). Accordingly, any parties requesting regulatory asset treatment will be required to demonstrate that the costs at issue are both unrecoverable in existing rates and that it is probable that such costs will be recoverable in future rates."), *aff'd sub nom., Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361 (D.C. Cir. 2004); Order No. 552, 58

that enables customers and other interested parties, as well as the Commission, to properly review the cost being recovered from FERC jurisdictional customers.

In both cases above, due to the smoothing effect[13] of the retail mechanism on fuel cost inputs to the cost-based rate mechanisms (including the FAC), there did not appear to be an adverse monetary impact on APCo's wholesale customers or any evidence that APCo inappropriately overcollected revenues on the basis of this unapproved regulatory asset accounting practice. Audit staff notes that in a period of fuel cost inflation such as the period under audit, fuel deferrals are mathematically bound to delay a utility's full collection of its fuel costs from customers. However, the Commission is "not bound by state commission decisions when examining wholesale rates."[14] Furthermore, since the Commission has "exclusive jurisdiction over wholesale sales, it is not enough to have state approval for recovery of costs when the costs include both wholesale and retail

Fed. Reg. at 18,000 ("Account 182.3 would include costs . . . *which have been, or are soon expected to be, authorized for recovery through rates*") (emphasis added).

[13] For the period examined by this audit, average prices for coal in the Mid-Atlantic region (including the Appalachian coal consumed by APCo) increased significantly, according to the Energy Information Administration. The WV and VA fuel proceedings are conducted annually and defer current short-term fuel price volatility over the following rate year. Hence, state-jurisdictional fuel factors incorporate a cost smoothing effect.

[14] *Piedmont Mun. Power Agency,* 162 FERC ¶ 61,109, at P 32 (2018) (granting Piedmont's complaint against Duke Energy Carolinas, LLC (DEC) that DEC's failure to file under section 205 of the FPA and obtain approval prior to recovering the costs recorded in a regulatory asset violated Commission precedent and policy). See also *Union Electric Company*, Opinion No. 354, 52 FERC ¶ 61,279 (1990); see also *Accounting and Ratemaking Treatment of Special Assessments Levied Under the Atomic Energy Act of 1954, as Amended by title XI of the Energy Policy Act of 1992*, 64 FERC ¶ 61,350, at 63,455 (1993) ("The requirement that there be uniform accounting, however, does not mean uniform ratemaking. There may be state commissions that may wish to prescribe a ratemaking treatment that is different from the ratemaking treatment for wholesale rates prescribed by this Commission."). See also *Wisconsin Public Service Corporation*, 120 FERC ¶ 61,177, at P 17 (2007) ("These costs are specifically before the Commission in this case. Future treatment of any other type of wholesale [cost or credit] is subject to Commission review, without deference to a state commission's treatment of any retail [cost or credit].").

amounts."[15] While audit staff does not contend that wholesale rates may never be affected by retail rate actions, the Commission's regulations and precedent require that any such rate parity be made explicit in utilities' tariffs.[16]

Recommendations

DAA recommends that APCo:

1. Revise policies and procedures regarding regulatory asset cost recovery to ensure that wholesale customers are held harmless of state-jurisdictional rate design except if authorized by the Commission.

2. Provide training to staff on the policies and procedures and conduct training regarding regulatory asset cost recovery to ensure that wholesale customers are held harmless of state-jurisdictional rate design except if authorized by the Commission. Also, develop a training program that supports the provision of periodic training in this area, as needed.

3. Cease any further impact to FERC-jurisdictional customers from state commission orders and rate adjustment clauses or, within 120 days of the issuance of this report, file to obtain Commission approval for the recovery of this regulatory asset in a separate section 205 application to the Commission requesting such recovery.

[15] *Piedmont Mun. Power Agency,* 162 FERC ¶ 61,109, at P 32 (2018). See also, *e.g.*, *Virginia Elec. and Power Co.,* 128 FERC ¶ 61,026, at P 22, 31-34 (2009) ("The treatment of a cost at the wholesale level as a regulatory asset is unrelated to whether a state regulator will or will not permit recovery of a rate that includes such costs in a wholesale customer's retail rates.").

[16] *See* 18 C.F.R. § 35.13(a)(2)(i)(E) ("If the utility models its filing in whole or in part on retail rate decisions or settlements, the utility must provide detailed calculations and a narrative statement showing how all retail rate treatments are factored into the cost of service.").

2. Classification of Purchased Power Costs

APCo improperly included approximately $7,606,000 of non-energy costs in the purchased power component of FAC calculations from 2019 to 2021, in which only energy-related economic purchases should be included. As a result, certain FERC-jurisdictional wholesale customers were overcharged by approximately $490,000.

Pertinent Guidance

- 18 C.F.R. § 35.14(a)(2) states in relevant part:

> [P]urchased economic power costs shall be the cost of:
>
> > (ii) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (a)(2)(iii) of this section.
> >
> > (iii) The total cost of the purchase of economic power, as defined in paragraph (a)(11) of this section, if the reserve capacity of the buyer is adequate independent of all other purchases where non-fuel charges are included in either Fb or Fm;
> >
> > (iv) Energy charges for any purchase if the total amount of energy charges incurred for the purchase is less than the buyer's total avoided variable cost

- 18 C.F.R. Part 101, Account 555, Purchased Power, states:

> A. This account shall include the cost at point of receipt by the utility of electricity purchased for resale. It shall include, also, net settlements for exchange of electricity or power, such as economy energy, off-peak energy for on-peak energy, spinning reserve capacity, etc. In addition, the account shall include the net settlements for transactions under pooling or interconnection agreements wherein there is a balancing of debits and credits for energy, capacity, etc. Distinct purchases and sales shall not be recorded as exchanges and net amounts only recorded merely because debit and credit amounts are combined in the voucher settlement.

B. The records supporting this account shall show, by months, the demands and demand charges, kilowatt-hours and prices thereof under each purchase contract and the charges and credits under each exchange or power pooling contract.

- Article 9 of Appalachian Power Company's Rate Schedule 23 states in relevant part:

  Fuel Cost (F) shall be the cost of:

  1. The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (c) below;

  2. The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis (included therein shall be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by Appalachian Company to substitute for its own higher cost energy) ….

- Section 5.04 of the Amended and Restated Inter-Company Power Agreement states in part:

  The transmission charges to be paid each month by the Sponsoring Companies shall be equal to the total costs incurred for such month by Corporation for the purchase of transmission service, ancillary services and other transmission-related services under the Tariff as reserved and scheduled by the Corporation to provide for the delivery of Available Power and Available Energy to the applicable delivery point under this Agreement[.]

Background

According to APCo's FERC Form No. 1 for 2022, APCo met approximately 46% of its 33,513,257 MWh energy requirements through energy purchases. While most of these purchases were made through PJM, approximately 21% of these purchases were made under bilateral contracts. Audit staff reviewed a number of these purchased power contracts to ensure that APCo was complying with the instructions of Account 555, Purchased Power, as well as the fuel cost recovery provisions in its tariffs. These tariffs dictate that only energy-related power purchases may be included in the determination of wholesale cost-based energy billings but provide for a separate rate mechanism to recover demand-related purchases.[17] APCo has accordingly configured its general ledger system to provide separate sub-accounts for energy-related purchases and demand-related purchases.

One of APCo's power suppliers is Ohio Valley Electric Corporation (OVEC), an affiliated generating company from which APCo receives a share of total power production. OVEC's itemized invoices are based on a cost-of-service formula that separately identifies Energy (Fuel), Energy (Non-Fuel), Demand, Transmission, Capacity, and other miscellaneous costs. Audit staff compared the OVEC invoice details to the related expenses that APCo recorded in its accounting books and found that APCo used its energy-purchases subaccount to record not only OVEC's energy charges, but also transmission and capacity charges. According to the OVEC Inter-Company Power Agreement, transmission charges consist of "transmission service, ancillary services and other transmission-related services." Such charges appear to be determined by megawatts, which are units of power (i.e., demand) rather than energy.

During the period tested from 2019 through 2021, OVEC billed APCo approximately $303,142,000, of which APCo included approximately $130,707,000 in FAC-input accounts. This included approximately $7,370,000 of transmission charges and $235,000 of capacity charges. APCo acknowledged that OVEC invoices the costs in question based on demand-related determinants, rather than energy-related determinants.

The costs from the OVEC billings are related to demand, capacity, and energy charges. Audit staff recognized that these different types of cost were assignable to some customers, but not all. Rate Schedules 151 and 155 dictate cost formulas for determining both energy (including fuel) and demand billings under their respective requirements service agreements. Audit staff did not find an appreciable difference between power purchases billed to customers using the demand formula as opposed to the energy formula. On the other hand, Rate Schedule 23 includes stated base rates for energy (including fuel) and demand billings, which only allows formulaic adjustments based on

[17] For example, APCo's Rate Schedules 151 and 155 are formula rates that compute billing rates for both energy and demand. In these two rate schedules, APCo's energy formula includes a cost component for energy related purchases. On the other hand, Rate Schedule 23 requires the use of stated rates for energy and demand billings, which only permits automatic rate adjustments for fuel and purchased power costs.

a FAC that conforms with the pro-forma FAC outlined at 18 C.F.R. § 35.14,[18] which among other things requires that demand or capacity-related purchases must be justified in advance with both economic and reliability conditions. APCo acknowledged that it made no such attempt to comply with these conditions. Thus, a misplaced demand-related purchase did adversely impact the customer served under Rate Schedule 23.

While the customers served under Rate Schedules 151 and 155 during the audit period were not adversely impacted by the assignment of these costs, APCo's affiliate customer served under Rate Schedule 23 was adversely affected. By incorrectly classifying $7,606,000 of demand- and capacity-related purchases as energy purchases under Rate Schedule 23, APCo overstated its fuel and purchased power revenue requirements and overcharged its Rate Schedule 23 customer by approximately $490,000.

Recommendations

DAA recommends that APCo:

4. Revise policies and procedures to ensure that purchased power costs are appropriately classified between energy-related and demand-related categories of purchases.

5. Train relevant staff on the revised policies and procedures for classifying purchased power costs between energy-related and demand-related categories and provide periodic training in this area, as needed.

6. Perform an analysis, and submit it to DAA for review, of the impact of misclassified purchased power costs on wholesale billings during the audit period, based on APCo's tariffs filed with the Commission, within 60 days of issuance of this audit report.

7. Submit a refund analysis, if applicable, within 60 days of issuance of this audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries during the audit period that resulted from the misclassified purchased power costs as identified pursuant to the analysis performed in response to Recommendation No. 6, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to receive refunds; and (5) period(s) for which refunds will be made.

[18] § 35.14 (2)(iv) states, "Energy charges for any purchase if the total amount of energy charges incurred for the purchase is less than the buyer's total avoided variable cost."

8. File a refund report with the Commission after receiving DAA’s assessment of the refund analysis.

9. Refund the amounts disclosed in the refund report to customers, with interest calculated in accordance with section 35.19a of the Commission’s regulations.

3. Fly Ash Sales Revenue and Expenses

APCo did not exclude the expenses it incurred in connection with fly ash sales for beneficial reuse from its wholesale cost-based fuel recovery formulas. By not excluding fly ash sales-related costs as required by its wholesale Requirements Service formulas, APCo overstated its revenue requirement by approximately $178,000.

Pertinent Guidance

- 18 C.F.R. Part 101, Account 501, Fuel, states in relevant part:

> A. This account shall include the cost of fuel used in the production of steam for the generation of electricity, including expenses in unloading fuel from the shipping media and handling thereof up to the point where the fuel enters the first boiler plant bunker, hopper, bucket, tank or holder of the boiler-house structure. Records shall be maintained to show the quantity, B.t.u. content and cost of each type of fuel used . . .
>
> ITEMS
>
> 15. Residual disposal expenses less any proceeds from sale of residuals.
>
> NOTE: Abnormal fuel handling expenses occasioned by emergency conditions shall be charged to expense as incurred.

- 18 C.F.R. Part 101, Account 511, Maintenance of Structures (Major Only), states:

> This account shall include the cost of labor, materials used and expenses incurred in the maintenance of steam structures, the book cost of which is includible in account 311, Structures and Improvements. (See operating expense instruction 2.)

- 18 C.F.R. Part 101, Account 512, Maintenance of Boiler Plant (Major Only), states in relevant part:

> A. This account shall include the cost of labor, materials used and expenses incurred in the maintenance of steam plant, the book cost of which is includible in account 312, Boiler Plant Equipment. (See operating expense instruction 2.)

- Appalachian Power Company Rate Schedules 151 and 155, Appendix B, Page A-14, "Production O&M Expense," state in relevant part:

9	Fuel – Account 501 (FERC Form-1 P 320)
10	Less: Fuel Handling
11	Less: Lignite Handling
12	Less: Sale of Fly Ash (Revenue & Expense)
. . .	
17	Total Fuel

Background

APCo owns and operates two coal-fired power plants, John E. Amos and Mountaineer, with a combined 4,283 MW of nameplate capacity.[19] These resources, both located in West Virginia, consumed approximately 26.3 million tons of bituminous coal from 2019 to 2022.[20] These generation facilities use emissions control devices to remove fly ash from the flue gas produced by coal combustion. Because fly ash can be used in various engineering and fabrication contexts, APCo sells a portion of its fly ash each year for beneficial reuse.

During the audit period, net proceeds from these sales were approximately $5.6 million. Regardless of whether fly ash is sold or disposed of, each of APCo's coal-fired facilities uses pneumatic pipes to transport compressed dry fly ash to holding silos. APCo then extracts the fly ash from the holding silos and either disposes of the ash or sells it. Fly ash buyers generally specify physical and chemical quality parameters, so in addition to safely recovering and storing fly ash, APCo must also maintain analysis protocols to confirm quality, procure handling and hauling services, and ensure that Company staff are available to supervise contractors and manage the relationships with fly ash buyers. APCo contracts with an ash marketing company that is responsible for extracting ash from the holding silos, hauling it to customers, and collecting sales revenues. The ash marketing company is exclusively responsible for ash hauling, while APCo incurs additional costs to market fly ash for resale, including contract management and plant-specific O&M costs.

[19] According to APCo's 2019-2022 FERC Form No. 1s, Pages 402 and 403.

[20] U.S. Energy Information Administration, via Electricity Data Browser.

APCo's wholesale cost-based formula rates specifically exclude all fly ash sales transactions from fuel cost formula inputs.[21] According to the formula rate template, this exclusion applies to both revenues and expenses, which means all sales proceeds and all related expenses. To accomplish this exclusion, APCo established a sub-account within Account 501 to track fly-ash-specific costs and proceeds.

To determine whether APCo complied with the cost exclusions of its Requirements Service formula rates, audit staff reviewed the accounting ledger details of Account 501, including the subaccount that corresponded to the "revenue & expense" exclusion for fly ash sales, as well as any related project codes and work orders included within the broad activity category of ash cleanup costs. As detailed below, audit staff's review of Account 501 cost and project details found that some ash sales and marketing costs were improperly included in the Requirements Service formula rates.

Contract Management and Supervision Costs

In addition to a dedicated sub-account for fly ash activity as discussed above, APCo maintains a project cost code for fly ash sales administration. Almost all these costs cover services rendered by APCo's affiliate, the AEP Service Company (AEPSC),[22] and are charged to Account 501. APCo explained that, in practice, the general ledger subaccount corresponding to the ash sales exclusion was mostly used to track ash sales net *proceeds* paid by the ash marketing company, whereas APCo's own direct costs, including internal labor and other *expenses* related to the sale of fly ash, were generally charged to other general ledger subaccounts within Account 501 along with the rest of the Company's ash disposal costs.

AEPSC's billings for fly ash sales administration include the labor and labor overheads of fuel buyers, legal, and fuel procurement leadership who are directly involved in fly ash sales, as well as employee expense reimbursements and other incidental costs. These activities included managing APCo's relationship with its coal ash marketing counterparty, representing APCo at coal ash industry events, and other related activities. Audit staff interviewed several of these individuals to confirm our understanding of the underlying accounting support. Based solely on the costs APCo

[21] *See* Appalachian Power Company Rate Schedules 151 and 155, Appendix B, Page A-14, Line 12: "Less: Sale of Fly Ash (Revenue & Expense)." Notwithstanding this step in APCo's cost-based formula rates, 18 C.F.R. Part 101 Account 501, Fuel includes Item 15, "Residual disposal expenses less any proceeds from sale of residuals."

[22] AEPSC is a centralized service company and is responsible for many of the supporting functions in APCo's steam power production utility function.

tracked in this ash administration project code, staff found that these costs amounted to approximately $120,000 during the audit period.

<u>Plant-Specific O&M Costs</u>

Audit staff also interviewed personnel at the Amos and Mountaineer plants with direct responsibility over ash disposal and sales operations. They explained that the ash marketing operations at each facility are functionally separate from ash disposal and landfill operations, which involve different shifts throughout the day and are supported by different contractors.

However, in reviewing project and work order details relating to coal combustion byproducts management, audit staff found additional utility O&M costs that were incurred to support fly ash marketing. Specifically, audit staff found that APCo used over 40 separate work orders during the audit period to track the incremental maintenance costs associated with ash sales and marketing activities. These were mostly charged to Account 512, Maintenance of Boiler Plant, with two work orders also impacting Account 511, Maintenance of Structures. Of the approximately $58,000 of costs included in the maintenance work orders, roughly $50,000 were related to boiler maintenance and, thus, were included in the energy component of APCo's formula rate, while roughly $8,000 were related to structures maintenance and thus were included in the demand component.

In both cases, APCo acknowledged that these maintenance costs resulted from maintenance work required in the course of supporting ash marketing operations. As noted above, certain facilities at APCo's power plants are dedicated primarily to fly ash sales, especially certain silos and ash unloading equipment used to support ash marketing. As these expenses are related to the sale of fly ash, these expenses should have been tracked in APCo's fly ash exclusion subaccount and recorded in FERC Account 501.[23] In the context of APCo's wholesale formula rate template, APCo should have reduced its expenses passed through Accounts 511 and 512 and instead included the approximately $58,000 of maintenance costs within the "Fly Ash Sales" formula adjustment line. This is because, according to APCo's formula, wholesale customers should be held harmless from incremental ash marketing costs.

<u>Summary</u>

In total, audit staff found that APCo included approximately $178,000 of costs incurred to support fly ash sales and marketing activities as inputs to its wholesale

[23] Account 501 includes Item 15: "Residual disposal expenses less any proceeds from sale of residuals." 18 C.F.R. Part 101, Account 501, Fuel.

formula rates ($120,000 in contract management and supervision costs and $58,000 in plant-specific O&M costs). However, these formulas state that such costs should be excluded from the revenue requirement. As a result of the improper inclusion of fly ash sales and marketing activities in its wholesale Requirements Service formulas, APCo overstated its revenue requirements and overbilled wholesale customers during the audit period. APCo should review its accounting for fly ash sales and correct the errors identified to prevent any future harm to wholesale customers.

Recommendations

DAA recommends that APCo:

10. Revise policies and procedures to ensure that all costs relating to fly ash sales are properly tracked and excluded from wholesale Requirements Service formulas.

11. Train relevant staff on the revised policies and procedures for excluding fly ash sales from wholesale Requirements Service formulas and provide periodic training in this area, as needed.

12. Perform an analysis, and submit it to DAA for review, of the impact of the improper inclusion of fly ash sales-related costs on wholesale billings during the audit period, based on APCo's tariffs filed with the Commission, within 60 days of issuance of this audit report.

13. Submit a refund analysis, if applicable, within 60 days of issuance of this audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries during the audit period that resulted from the improper inclusion of fly ash sales-related costs as identified pursuant to the analysis performed in response to Recommendation No. 12, plus interest; (2) determinative components of the refund; (3) refund method; (4) customers to receive refunds; and (5) period(s) for which refunds will be made.

14. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

15. Refund the amounts disclosed in the refund report to customers, with interest calculated in accordance with section 35.19a of the Commission's regulations.

4. FERC Form No. 580 Reporting

APCo did not properly follow the FERC Form No. 580 instructions and, therefore, did not report all required information in its FERC Form No. 580 filings. These actions affected the transparency, accuracy, and usefulness of certain sections of the FERC Form No. 580.

Pertinent Guidance

- FERC Form No. 580 Instructions, Question 2a, states in part:

  Provide the following information regarding non-transmission related wholesale automatic adjustment clauses (AACs) your Utility had on file with the Commission …

- FERC Form No. 580 Instructions, Question 3, states:

  If during the [biennial reporting] period, the Utility had any contracts or agreements for the purchase of either energy or capacity under which all or any portion of the purchase costs were passed through a fuel adjustment clause (FAC), for each purchase from a PURPA Qualifying Facility (QF) or Independent Power Producer (IPP), provide the information requested in the non-shaded columns of the table below. Provide the information separately for each reporting year . . . Do not report purchased power where none of the costs were recovered through a FAC.

- FERC Form No. 580 Instructions, Question 6, states:

  For each fuel supply contract, of longer than one year in duration, in force at any time during [the biennial reporting period], where costs were subject to 18 C.F.R. § 35.14, (including informal agreements with associated companies), provide the requested information. Report the information individually for each contract, for each calendar year. [No response to any part of Question 6 for fuel oil no. 2 is necessary.] Report all fuels consumed for electric power generation and thermal energy associated with the production of electricity. Information for only coal, natural gas, and oil should be reported.

Background

Audit staff performed a review of the FERC Form No. 580 filings made by APCo pertaining to the audit period. Staff's evaluation focused on the completeness and accuracy of APCo's required disclosures and APCo's compliance with the instructions accompanying FERC Form No. 580. As a result of this review, staff found certain omissions or inconsistencies.

FERC Form No. 580, Question 2 – Wholesale Automatic Adjustment Clauses:

According to APCo's 2018-2019 FERC Form No. 580 submission, there were two AACs on file with the Commission.[24] During the audit, APCo acknowledged that there was a third fuel adjustment clause on file, an affiliate power sale agreement with Kingsport Power Company,[25] which was omitted from APCo's 2018-2019 FERC Form No. 580 due to administrative oversight. APCo referenced this third AAC in its 2020-2021 FERC Form No. 580.

FERC Form No. 580, Question 3 – Purchased Power Reporting:

FERC Form No. 580, Part 3, requires utilities to provide certain information regarding cost items recovered through an FAC. For purchases where the utility only recovers energy charges, responses are required to the following:

a) Was the total of such charges less than the total avoided variable costs?
b) Was economic dispatch used to determine whether the charges were less than avoided costs?

In APCo's 2018-2019 FERC Form No. 580, the answer to question (a) was left blank for all reported PPAs, while question (b) was reported as "No" for all items. APCo subsequently acknowledged that the responses to question (a) should have been "Yes."

Audit staff also noted that the dollar amounts reported in APCo's 2018-2019 FERC Form No. 580 in the columns "Purchase Cost" and "Annual amount recovered through an AAC ($)" were equal. However, these purchases far exceed the annual energy requirements of APCo's FERC-jurisdictional customers and are also made to satisfy retail-jurisdictional energy requirements. While the 2020-2021 FERC Form No. 580 shows different amounts between the two columns in question, APCo explained that these differences were because of a disallowance by a retail-jurisdictional regulator. Audit staff notes that only the portion of purchased power costs that was recovered through FERC-approved AACs should be reported in that column.

[24] Rate Schedule 151 (referencing Docket No. ER12-216) and Rate Schedule 155 (referencing Docket No. ER12-221).

[25] Rate Schedule 23 (referencing Docket No. ER09-288).

APCo should evaluate their disclosures regarding purchased power contracts to ensure that such purchased power agreements are properly disclosed as required by the FERC Form No. 580.

FERC Form No. 580, Question 6 – Fuel Supply Contracts:

FERC Form No. 580 requires utilities to report contract details for "each fuel supply contract, of longer than one year in duration, in force at any time" during the biennial reporting period. For each contract, the utility must disclose "Contract Signing Date," "Contract Expiration Date," and many other details regarding contract types and fuel characteristics. APCo reported three contracts in the 2018-2019 reporting period. Audit staff found eight additional contracts that represented an obligation of longer than one year in duration and, thus, should have been disclosed. The intent of the contract data collection under FERC Form No. 580 is to inform the Commission and the public of long-term contractual agreements for fuel supply. Therefore, these should have also been reported on APCo's FERC Form No. 580.

Nature of omission	Number of contracts	Contracted tons not reported	Weighted average contract price ($/ton)
Fully omitted from 2018-2019 disclosure	1	4,415,581	$39.54
Partially omitted[26] from 2018-2019 disclosure	2	4,154,084	$37.42
> 12 months as executed[27]	5	2,029,000	$58.03

In addition, the FERC Form No. 580 provides a data field for utilities to report the delivery status of each contract by year with the field "Coal (x10^3 tons) not delivered by end of contract year." The intent of this section of FERC Form No. 580 is for utilities to reconcile contracted fuel quantity, actual delivered quantity, and undelivered quantity, on the basis of each contract reported. However, in both its 2018-2019 and 2020-2021 FERC Form No. 580 reports, APCo did not reconcile its delivery quantities. Audit staff noted the following reconciliation discrepancies that should have been reported as undelivered quantities:

[26] For these long-term contracts, APCo reported one contract year correctly but omitted the other contract year from the relevant reporting period.

[27] While these contracts entitled APCo to a delivery period of exactly 12 months, they were fully executed prior to the beginning of those delivery periods. Thus, they were in force for "longer than one year" and, as required by the FERC Form No. 580 instructions, should have been reported.

FERC Form No. 580 Year	Contract Reference	Contracted Amount (000's Tons)	Deliveries (000's Tons)	Variance (000's Tons)
2018-2019	02-10-06-901	3,000	2,497	503
2020-2021	02-40-19-003	240	139	101
2020-2021	02-10-06-901	2,750	1,430	1,320
2020-2021	02-10-12-900	2,100	1,802	298

APCo explained that the 2018-2019 discrepancy was an oversight and that it should have reported 3,000,000 tons delivered; that the 101,000 undelivered tons from the first 2020-2021 contract was settled financially in 2022 for $2.7 million as a credit to APCo; and the final two contracts totaling 1,618,000 tons were, at the time of filing, subject to litigation. Specifically, in 2022, APCo filed two civil suits against one of its largest coal suppliers, alleging breach of contract for significant undelivered quantities of coal.[28] This supplier filed counterclaims, alleging that APCo, not the supplier, was at fault for failing to arrange for deliveries of available coal. Discovery and pre-trial filings were scheduled to take place in late 2024, but APCo made filings to dismiss all claims in August 2023, stating that a settlement had been reached. Any outcome from the out-of-court resolution of these matters could have a significant impact on APCo's fuel-related costs.

APCo is responsible for the transparency and accuracy of its required disclosures and should ensure that all relevant contract data is correctly reported on FERC Form No. 580 as required by the Commission.

Recommendations

DAA recommends that APCo:

16. Revise policies and procedures regarding FERC Form No. 580 reporting of tariffs, power purchases, and fuel supply contracts to ensure that complete and accurate information is reported in accordance with the Commissions instructions in FERC Form No. 580.

17. Provide training for relevant personnel to ensure that FERC Form No. 580 reporting policies and procedures, as revised, are complied with.

[28] *See Appalachian Power Company v. ACNR Coal Sales, Inc.*, Case No. 22-CV-003705, Complaint filed in Franklin County, Ohio Court of Common Pleas (June 2022); *Appalachian Power Company v. ACNR Coal Sales, Inc.*, Case No. 653609, Complaint filed in New York Supreme Court, New York County (September 2022).

18. Refile the FERC Form No. 580 for the 2018-19 and 2020-21 reporting periods to provide complete and accurate responses to Questions 2, 3, and 6 as discussed in the body of this finding.

V. APCo's Response to the Audit Report

AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

Jessica A. Cano
Asst. General Counsel - FERC
American Electric Power Service Corporation
1 Riverside Plaza
Columbus, Ohio 43215
(614) 716-2921
jacano@aep.com

February 26, 2024

Kristen Fleet
Director and Chief Accountant
Division of Audits and Accounting
Office of Enforcement
Federal Energy Regulatory Commission
888 First Street, NE, Room 5K-13
Washington, DC 20426
Email: Kristen.Fleet@ferc.gov

Re: Docket No. FA22-1-000, Draft Audit Report

Dear Ms. Fleet,

On February 9, 2024, American Electric Power Service Corporation ("AEPSC") received the Draft Audit Report issued in the above-referenced docket. The Draft Audit Report contains four findings and 18 recommendations. Pursuant to Section 41.1(b) of the Commission's regulations and consistent with your request, AEPSC is hereby responding to the Draft Audit Report on behalf of Appalachian Power Company ("ApCo") as follows:

Findings:

1. <u>Amortization of Retail Regulatory Assets</u>

   ApCo disagrees that it was improper to include the amortization of regulatory assets arising from state-jurisdictional fuel adjustment clauses (over/under recoveries) in its Commission-jurisdictional cost-based formula rates. Information regarding the amortization of such regulatory assets as an input to the rate calculation was included in ApCo's initial filing seeking approval of the cost-based formula rate contract, which was accepted by the Commission.[1] In addition, the customer has been aware of this input since 2006 and has not contested it. Nonetheless, ApCo acknowledges that the Commission did not explicitly approve this input. Accordingly, ApCo will not contest this finding.

[1] *Appalachian Power Company,* Docket No. ER06-848 (May 26, 2006) (via delegated letter order).

2. Classification of Purchased Power Costs

   ApCo accepts this finding and the related recommendations.

3. Fly Ash Sales Revenue and Expense

   ApCo accepts this finding and the related recommendations.

4. FERC Form No. 580 Reporting

   ApCo accepts this finding and the related recommendations.

As requested at page 4 of the Draft Audit Report, ApCo will submit within 30 days of the issuance of the final audit report a plan for implementing the audit recommendations. ApCo also will make quarterly reports of its progress in completing each corrective action and provide copies of any written policies and procedures developed in response to the recommendations.

Sincerely,

s/ Jessica A. Cano

Jessica A. Cano
Asst. General Counsel - FERC
American Electric Power
Service Corporation

January 12, 2024

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

RE: *Application of Appalachian Power Company, To decrease its fuel factor pursuant to § 56-249.6 of the Code of Virginia*, Case No. PUR-2023-00156

Dear Mr. Logan:

Please accept for filing the supplemental testimony of Commission Staff ("Staff") witness Patrick W. Carr in Case No. PUR-2023-00156.

Staff will offer the enclosed testimony at the evidentiary hearing in this case that is scheduled for January 17, 2024. Thank you for your assistance in this matter.

Sincerely,

/s/ C. Austin Skeens
C. Austin Skeens

CAS:hca
Enclosures

cc: Service List

CERTIFICATE OF SERVICE

I hereby certify that on this 12th day of January 2024, a true copy of the foregoing was electronically mailed to all persons on the official Service List in this matter. The Service List is available from the Clerk of the Commission.

/s/ C. Austin Skeens
C. Austin Skeens

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

SUPPLEMENTAL STAFF TESTIMONY

APPALACHIAN POWER COMPANY

To decrease its fuel factor pursuant to § 56-249.6 of the Code of Virginia

Supplemental Testimony of:

Patrick W. Carr
Division of Utility Accounting and Finance

PUR-2023-00156

January 12, 2024

Summary of the Supplemental Testimony of Patrick W. Carr

My supplemental testimony provides an update on the status of Case Nos. 21-0339-E-ENEC, 22-0393-E-ENEC, and 23-0377-E-ENEC before the Public Service Commission of West Virginia ("WVPSC"). Additional filings, including a WVPSC order, have been filed in those dockets since my prefiled direct testimony was filed on December 20, 2023.

SUPPLEMENTAL STAFF TESTIMONY
OF
PATRICK W. CARR

APPALACHIAN POWER COMPANY
CASE NO. PUR-2023-00156

JANUARY 12, 2024

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND THE POSITION YOU HOLD WITH THE STATE CORPORATION COMMISSION.

A. My name is Patrick W. Carr. I am a Deputy Director with the State Corporation Commission's Division of Utility Accounting and Finance.

Q. ARE YOU THE SAME PATRICK W. CARR WHO FILED DIRECT TESTIMONY IN THIS PROCEEDING ON DECEMBER 20, 2023?

A. Yes.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR SUPPLEMENTAL TESTIMONY.

A. My December 20, 2023 prefiled direct testimony provided a then-current update on the status of Case Nos. 21-0339-E-ENEC, 22-0393-E-ENEC, and 23-0377-E-ENEC before the Public Service Commission of West Virginia ("WVPSC"). The purpose of my supplemental testimony is to simply provide updates to that status. The conclusions and recommendations contained in my prefiled direct testimony have not changed.

Q. PLEASE PROVIDE UPDATES TO THAT STATUS.

A. Since December 20, 2023, there have been several developments in those dockets, the most significant of which was the WVPSC's issuance of an order on January 9, 2024 ("WV Order").[1] The WV Order will be discussed further below. Prior to the issuance of the WV Order, the following pertinent documents had been filed in each of the three dockets referenced above:

- On December 21, 2023, APCo filed excerpts of the prefiled direct testimonies from this proceeding of myself and Staff witness Oliver C. Collier.[2]
- On December 26, 2023, the Consumer Advocate Division of West Virginia ("WV CAD") filed an objection to the above filing.[3]
- On December 27, 2023, APCo, its affiliate Wheeling Power Company, the West Virginia Energy Users Group, and the West Virginia Coal Association filed a proposed Joint Stipulation and Agreement for Settlement.[4]
- On December 28, 2023, Staff of the WVPSC filed a letter opposing the stipulation.[5]

[1] https://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=616349&NotType=WebDocket

[2] https://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=615636&NotType=WebDocket

[3] https://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=615748&NotType=WebDocket

[4] https://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=615810&NotType=WebDocket

[5] https://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=615845&NotType=WebDocket

- On January 2, 2024, the Kanawha County Commission filed a letter opposing the stipulation.[6]
- On January 5, 2024, WV CAD filed a letter opposing the stipulation.[7]

Q. PLEASE DISCUSS THE WV ORDER.

A. The deferred fuel costs of APCo and Wheeling Power Company at issue in the WV proceedings totaled $552.9 million. The WV Order disallowed $231.8 million.[8] It allowed recovery of the remaining $321.1 million over a ten-year period with financing costs of four percent per year. It also rejected the proposed stipulation.

The WV Order explained that the $231.8 million disallowance "is due to the imprudent decisions and management that resulted in insufficient stockpiles of coal to self-generate more energy to serve load … ."[9] It further explained that it found a "failure to maintain adequate coal stockpiles and incoming coal supplies to self-generate even when doing so could reduce ENEC costs."[10] The disallowance amount is based on the WVPSC's calculation of the amount of additional energy margins that could have been produced if APCo and Wheeling Power Company had had sufficient coal to generate electricity in

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[6] https://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=615891&NotType=WebDocket

[7] https://www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=616155&NotType=WebDocket

[8] $136.4 million of this related to APCo and $95.4 million is attributable to Wheeling Power Company. WV Order at 27. All figures are West Virginia-jurisdictional.

[9] *Id.* at 21.

[10] *Id.* at 25. The Expanded Net Energy Cost ("ENEC") is the mechanism by which APCo recovers fuel and certain other costs in West Virginia.

hours when the WVPSC determined it was economical to do so during the two-year period of March 1, 2021 through February 28, 2023.[11]

The decision to allow recovery of the remaining amount only over an extended period at a four-precent financing cost rate is "in recognition of the very high remaining under-recovery balance and the likelihood that the imprudence in fuel planning, fuel practices and market strategies that caused a lack of adequate coal supplies, contributed to the inability or unwillingness of the Companies to offset a portion of the remaining $321,106,227 under-recovery by different decisions for taking or keeping plants out-of-service … ."[12]

Q. DOES ANYTHING REGARDING THIS UPDATE CHANGE OR OTHERWISE AFFECT THE CONCLUSIONS AND RECOMMENDATIONS CONTAINED IN YOUR DECEMBER 20, 2023 PREFILED DIRECT TESTIMONY?

A. No. This supplemental testimony is intended only as an update for the State Corporation Commission's information.

Q. DOES THIS CONCLUDE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes, it does.

[11] *Id.* at 22-28.

[12] *Id.* at 29.

ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Freeman	√		
Krevda	√		
Ober	√		
Ziegner	√		

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE APPLICATION OF INDIANA MICHIGAN POWER COMPANY FOR APPROVAL OF A FUEL COST ADJUSTMENT FOR ELECTRIC SERVICE APPLICABLE FOR THE BILLING MONTHS OF OCTOBER 2020 THROUGH MARCH 2021 AND FOR APPROVAL OF RATEMAKING TREATMENT FOR COST OF WIND POWER PURCHASES PURSUANT TO CAUSE NOS. 43328, 43750, 44034 AND 44362	)	**CAUSE NO. 38702 FAC 85** **APPROVED: SEP 23 2020**

ORDER OF THE COMMISSION

Presiding Officer:
Loraine L. Seyfried, Chief Administrative Law Judge

On July 31, 2020, Indiana Michigan Power Company ("I&M" or "Applicant") filed with the Indiana Utility Regulatory Commission ("Commission") its Verified Application For a Fuel Cost Adjustment for electric service to be applicable during the October 2020 through March 2021 billing months, pursuant to the provisions of Ind. Code § 8-1-2-42, and for approval of I&M's ratemaking treatment of wind power purchase costs. On the same day, I&M filed its case-in-chief.

On August 20, 2020, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its case-in-chief.

The Commission scheduled an evidentiary hearing in this Cause for September 9, 2020, at 9:30 a.m. in Room 224 of the PNC Center, 101 W. Washington Street, Indianapolis, Indiana. A Docket Entry was issued on August 31, 2020, advising that in accordance with Indiana Governor Holcomb's Executive Orders concerning the COVID-19 pandemic, the hearing would be conducted via teleconference and providing related participation information. Applicant and the OUCC participated in the evidentiary hearing by counsel via teleconference. The testimony and exhibits of Applicant and the OUCC were admitted without objection.

The Commission, based upon the applicable law and the evidence of record, now finds as follows:

1. **Notice and Jurisdiction.** Proper notice of the public hearing in this Cause was published as provided by law. I&M is an Indiana corporation engaged in rendering electric public utility service in the State of Indiana and is a public utility within the meaning of the Public Service Commission Act, as amended. Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to Applicant's fuel cost charge. Therefore, the Commission has jurisdiction over the Applicant and the subject matter of this proceeding.

2. **Applicant's Request.** In its Verified Application, Applicant seeks Commission approval to implement its proposed fuel adjustment cost during the billing months of October 2020 through March 2021 pursuant to Ind. Code § 8-1-2-42 and I&M's ratemaking treatment of wind power purchase costs. I&M's application continues the semi-annual filing process in place since 1999. Applicant also requests the Commission find that the applicable provisions of Ind. Code § 8-1-2-42 are satisfied.

3. **Source of Fuel and Coal Decrement Pricing.** As a condition of receiving its requested fuel adjustment cost, Applicant must demonstrate compliance with the statutory requirements of Ind. Code § 8-1-2-42(d)(1) by making every reasonable effort to acquire fuel and generate or purchase power, or both, so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. Applicant's witness Jeffrey C. Dial summarized I&M's long-term coal supply agreements and described I&M's coal purchasing strategy. He discussed how recent changes in the energy market and loss of demand for electricity have impacted coal-fired generation for I&M and explained the options I&M explored to mitigate the reduced coal consumption. He described I&M's use of coal decrement pricing and identified the inputs into the calculation of the decrement pricing. He explained that coal decrement pricing involves reducing the market offer provided to PJM for the Rockport plant by an amount equal to or less than the liquidated damages that would be applicable should I&M not meet contractual minimums. Mr. Dial stated that I&M continues to evaluate the need for decrement pricing and that I&M will update its testimony regarding the use of decrement pricing in future FAC proceedings. OUCC witness Michael D. Eckert recommended that Applicant file testimony, schedules, and workpapers as appropriate to justify and support the need for, and utilization of, coal decrement pricing when necessary. Applicant's witness Keith A. Steinmetz described the major nuclear fuel contracts and actions taken to minimize I&M's nuclear fuel costs. Applicant's evidence demonstrates that it has made every reasonable effort to obtain available fuel or power as economically as possible. Based on the evidence presented, as indicated here and further below, the Commission finds that Applicant is endeavoring to acquire fuel for its internal generation or purchase power so as to provide electricity at the lowest fuel cost reasonably possible.

4. **Operating Expenses.** Ind. Code § 8-1-2-42(d)(2) requires the Commission to find that increases in a utility's fuel cost have not been offset by decreases in other expenses. Applicant's fuel expenses for the 12-month period ended May 31, 2020 in the amount of $193,449,000, as reflected on Applicant's Attachment 1-F, Schedule 1, Column 9, Line 31, of Applicant's Exhibit 1, are less than the corresponding amount determined in Applicant's last base rate order (Cause No. 45235) of $195,326,000, by an amount of $1,877,000. Applicant's filing demonstrates that I&M's actual fuel costs are lower than the fuel costs included in Cause No. 45235. Accordingly, as there are no increased fuel costs to be offset, we find that I&M is in compliance with the statutory requirements of Ind. Code § 8-1-2-42(d)(2).

5. **Return Earned.** I&M' s witness David L. Hille explained that pursuant to the Order in Cause No. 45235, I&M is authorized to earn an electric operating income of $263,334,000. According to Applicant's Attachment 1-F, Schedule 1, attached to Applicant's Exhibit 1, for the 12 months ended May 31, 2020, I&M earned an actual jurisdictional net operating income of $261,188,000. OUCC Witness Michael D. Eckert recommended I&M be required to prorate the

earnings test for the 12 months ended May 31, 2020 between I&M's last two base rate cases (Cause Nos. 44967 and 45235). Since this would not impact the factor in this case, he recommends I&M provide the updated amount in its next FAC filing and reflect the updated amount in the earnings bank calculation, and we concur. In its next FAC, I&M shall reflect the updated amount in the earnings bank calculation to insure that the earnings bank is accurate. Therefore, we find that during the test period for this Cause, I&M has not earned a return in excess of its authorized return and is in compliance with the statutory requirements of Ind. Code § 8-1-2-42(d)(3).

6. **Estimating Techniques.** I&M's overall weighted average fuel cost estimating error during the months of the reconciliation period of December 2019 through May 2020 was an overestimation of 13.12%. I&M's witness Mr. Hille noted that during much of the reconciliation period, the primary driver of the lower than forecasted costs were higher than forecasted nuclear generation and lower than forecasted sales. That combination resulted in a higher percentage of the lower total level of sales being supplied by the lower fuel cost nuclear generation, thereby reducing total costs. I&M projected its fuel costs for the billing months of October 2020 through March 2021. I&M's filing demonstrates that the estimates of I&M's prospective average fuel costs for the projected period are reasonable after taking into consideration the difference between I&M's projected and actual fuel cost for the reconciliation period of December 2019 through May 2020. No party presented any evidence to the contrary. Based on the evidence, we find that Applicant's estimating techniques are reasonable and its estimate of fuel costs for October 2020 through March 2021 should be accepted.

7. **Wind Power Purchases.** Applicant's witness Nancy A. Heimberger testified in support of I&M's request for approval of ratemaking treatment for costs related to I&M's wind power purchases. Ms. Heimberger testified that I&M is projected to receive energy from the Fowler Ridge phase one and phase two wind farms, the Wildcat wind farm, and the Headwaters wind farm. OUCC witness Michael D. Eckert testified that he reviewed the settlement agreement and subsequent Order in Cause No. 43328 and that I&M has forecasted the costs of wind power that it will be incurring in the future by using the cost per MWh from the Wind Power Purchase Agreements and has identified the wind power MWhs and costs on separate line items. I&M's wind purchases are shown consistent with the Commission's Order in Cause No. 38702 FAC 63 and inclusion of these costs conforms to the Commission's November 28, 2007 Order in Cause No. 43328, the January 6, 2010 Order in Cause No. 43750, the September 21, 2011 Order in Cause No. 44034, and the November 25, 2013 Order in Cause No. 44362. Accordingly, the record supports, and the Commission so finds, that the wind power purchase costs reflected in I&M filings are reasonable and approves the ratemaking treatment of such costs.

8. **Fuel Cost Adjustment Charges.** Attachment 1-C, attached to Applicant's Exhibit 1, sets forth I&M's actual incurred fuel costs for the reconciliation period. I&M's fuel costs for the reconciliation period were over-recovered, in the amount of $29,919,785, based upon projected fuel costs for those months previously approved by the Commission.

Applicant's total estimated cost of fuel for the billing months of October 2020 through March 2021 is $121,091,838 and its total estimated sales are 9,967,565 MWhs. I&M's estimated cost of fuel, as indicated on Applicant's Attachment 1-B, Schedule 1, line 23 of Applicant's Exhibit 1, is therefore 12.149 mills per kWh. Combining the variance factor with the estimated per kWh cost of fuel, subtracting the base cost of fuel in Cause No. 45235 and adjusting for Indiana Utility Receipts Tax, results in a proposed total fuel factor of (4.849) mills per kWh.

In accordance with the basing point approved by the Commission in Cause No. 45235 and the evidence presented in this proceeding, we find Applicant is authorized to apply a fuel cost adjustment of (4.849) mills per kWh to Applicant's Indiana retail tariffs for the billing months of October 2020 through March 2021. The typical residential bill of 1,000 kWh per month will decrease by $3.24 or 2.22% compared to the factor approved in Cause No. 38702 FAC 84 (excluding taxes).

9. **Required Reporting.** I&M's FAC filing continues to utilize the semi-annual filing practice and such practice was unopposed; accordingly, the Commission has approved a fuel cost factor for a six-month period. However, as required by Ind. Code § 8-1-2-42(c), the OUCC should perform a quarterly review of I&M's books and records pertaining to the cost of fuel and report to the Commission by November 25, 2020. Applicant has agreed to cooperate and provide reasonable support in the OUCC's fulfillment of this requirement.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. In accordance with Ind. Code § 8-1-2-42, the fuel cost adjustment charge set forth in Finding No. 8 above for the billing months of October 2020 through March 2021 is approved.

2. I&M's ratemaking treatment for the cost of wind power purchases pursuant to the Commission's Orders in Cause Nos. 43328, 43750, 44034, and 44362 is approved.

3. Prior to implementing the rate, Applicant shall file the tariff and applicable rate schedules under this Cause for approval by the Commission's Energy Division.

4. In Cause No. 38702 FAC 86, I&M will report the authorized earnings level applicable to the earning period in this Cause (June 1, 2019 through May 31, 2020) on a pro-rated basis to account for the implementation of I&M's new rates and charges in Cause No. 45235 during that period.

5. This Order shall be effective on and after the date of its approval.

HUSTON, FREEMAN, KREVDA, OBER AND ZIEGNER CONCUR:

APPROVED: SEP 23 2020

I hereby certify that the above is a true and correct copy of the Order as approved.

Mary M. Schneider
Secretary of the Commission

Commissioner	Yes	No	Not Participating
Huston	√		
Freeman	√		
Krevda			√
Veleta	√		
Ziegner	√		

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE APPLICATION OF INDIANA MICHIGAN POWER COMPANY FOR APPROVAL OF A FUEL COST ADJUSTMENT FOR ELECTRIC SERVICE APPLICABLE FOR THE BILLING MONTHS OF NOVEMBER 2022 THROUGH APRIL 2023 AND FOR APPROVAL OF RATEMAKING TREATMENT FOR COST OF WIND POWER PURCHASES PURSUANT TO CAUSE NOS. 43328, 43750, 44034, AND 44362	)	**CAUSE NO. 38702 FAC 89** **APPROVED: OCT 26 2022**

<u>ORDER OF THE COMMISSION</u>

Presiding Officer:
Ann Pagonis, Administrative Law Judge

On August 1, 2022, Indiana Michigan Power Company ("I&M" or "Applicant") filed with the Indiana Utility Regulatory Commission ("Commission") its Verified Application For a Fuel Cost Adjustment for electric service to be applicable during the November 2022 through April 2023 billing months, pursuant to the provisions of Ind. Code § 8-1-2-42, and for approval of I&M's ratemaking treatment of wind power purchase costs. On the same day, I&M filed its case-in-chief.

On September 6, 2022, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its case-in-chief.

The Commission conducted an evidentiary hearing in this Cause on October 13 2022, at 9:30 a.m. in Room 224 of the PNC Center, 101 W. Washington Street, Indianapolis, Indiana. Applicant and the OUCC participated in the hearing. At the hearing, the direct testimony and attachments of Applicant and the OUCC were admitted into evidence without objection.

The Commission, based upon the applicable law and the evidence of record, now finds as follows:

1. **<u>Notice and Jurisdiction</u>.** Proper notice of the public hearing in this Cause was published as provided by law. I&M is an Indiana corporation engaged in rendering electric public utility service in the State of Indiana and is a public utility within the meaning of the Public Service Commission Act, as amended. Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to Applicant's fuel cost charge. Therefore, the Commission has jurisdiction over the Applicant and the subject matter of this proceeding.

2. **<u>Applicant's Request</u>.** In its Verified Application, Applicant seeks Commission approval to implement its proposed fuel adjustment cost during the billing months of November 2022 through April 2023 pursuant to Ind. Code § 8-1-2-42 and I&M's ratemaking treatment of wind power purchase costs. I&M's application continues the semi-annual filing process in place since 1999. Applicant also requests the Commission find that the applicable provisions of Ind. Code § 8-1-

2-42 are satisfied.

3. Source of Fuel and Coal Increment Pricing. As a condition of receiving its requested fuel adjustment cost, Applicant must demonstrate compliance with the statutory requirements of Ind. Code § 8-1-2-42(d)(1) by making every reasonable effort to acquire fuel and generate or purchase power, or both, so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. Applicant's witness Jeffrey C. Dial summarized I&M's long-term coal supply agreements and described I&M's coal purchasing strategy. He discussed how Applicant utilized the Cora transloading facility during the reconciliation period because of a fire at Cook Coal Terminal. Mr. Dial explained that even though Cook Coal Terminal has returned to service, congestion at Cora and unrelated rail transportation issues have impacted the availability of coal. Mr. Dial explained coal prices have increased during the reconciliation period and how the energy market has impacted coal-fired generation for I&M. Mr. Dial stated that I&M utilized increment pricing to ensure Applicant had adequate coal available and will continue to evaluate the need for pricing strategies and that I&M will update its testimony regarding the use of such pricing in future FAC proceedings. Applicant's witness Stegall further explained how I&M utilized increment pricing in support of managing each unit's coal inventory. Applicant's witness Keith A. Steinmetz described the major nuclear fuel contracts and actions taken to minimize I&M's nuclear fuel costs.

OUCC witness Gregory T. Guerrettaz discussed I&M's cost of nuclear and coal and how an increase in generation affected the coal inventory. Witness Guerrettaz recommended that Applicant explain to the Commission the generation strategy and coal inventory management being used for Rockport Unit 1 with Rockport Unit 2 becoming a merchant plant as well as require I&M to provide all new Nuclear Fuel Leases and bid results at the time when workpapers are provided. OUCC witness Michael D. Eckert discussed how high-cost natural gas has resulted in an increase in demand for coal-fired electricity. Witness Eckert explained how the lack of available of coal has resulted in I&M's modifying its Day-Ahead Offer Price to manage the coal inventory and recommended that Applicant provide the Commission with information on how it proposes to address its the coal inventory, the calculation inputs of coal decrement or increment pricing, and testimony on barging and transloading costs.

Applicant's evidence demonstrates that it has made every reasonable effort to obtain available fuel or power as economically as possible. No party presented any evidence to the contrary. Based on the evidence presented, as indicated here and further below, the Commission finds that Applicant is endeavoring to acquire fuel for its internal generation, or purchase power, so as to provide electricity at the lowest fuel cost reasonably possible.

4. Operating Expenses. Ind. Code § 8-1-2-42(d)(2) requires the Commission to find that increases in a utility's fuel cost have not been offset by decreases in other expenses. Applicant's fuel expenses for the 12-month period ended May 31, 2022 in the amount of $204,427,000, as reflected on Applicant's Attachment 1-F, Schedule 1, Column 9, Line 38, of Applicant's Exhibit 1, are more than the corresponding amount determined in Applicant's last base rate order (Cause No. 45235) of $185,803,000, by an amount of $18,624,000. Applicant's filing demonstrates that I&M's actual fuel costs are higher than the fuel cost included in Cause No. 45235. Accordingly, any increases in fuel costs must be offset by decreases in other non-fuel costs, we find that I&M is in compliance with the statutory requirements of Ind. Code § 8-1-2-42(d)(2).

5. <u>Return Earned.</u> Ms. Seger-Lawson explained that pursuant to the Order in Cause No. 45235, I&M is authorized to earn an electric operating income of $296,735,000. That amount (when adjusted for Cause Nos. 44182 and 45245) results in an authorized level for the 12 months ended May 31, 2022 of $274,113,000. According to Applicant's Attachment 1-F, Schedule 1, attached to Applicant's Exhibit 1**,** for the 12 months ended May 31, 2022, I&M earned an actual jurisdictional net operating income of $295,176,000. This results in I&M's actual return being more than its authorized return for the most recent 12-month period and the sum of the differentials for the relevant period is also greater than zero, meaning that the Commission should find that the "return" test of Ind. Code § 8-1-2-42(d)(3) is not satisfied. Therefore, in accordance with Ind. Code § 8-1-2-42(d)(3) a reduction to I&M's FAC factor is necessary. This amount is to be the lower of the 12-month over earnings and the sum of the differentials for the relevant period. The over-earnings amount for the 12-month period was $21,063,000 and the sum for the differential period is $63,558,000. For this reason, I&M will base its credit on the 12-month period amount and divide it in half due to I&M filing semi-annual FAC proceedings. This results in a total FAC credit of $10,531,000, or $14,107,000 grossed up for taxes.

OUCC witness Guerrettaz affirmed Applicant's conformity with the requirements of Cause No. 38702 FAC 86.

Upon our consideration of the record evidence, the Commission finds I&M has properly determined the authorized operating income for the 12 months ended May 31, 2022, and properly reflected the return authorized in Cause Nos. 44182 and 45245. Thus, by the mechanics of the applicable statute, the Commission finds I&M appropriately calculated and applied the reduction amount to its proposed fuel factor in light of the return earned by I&M during the 12 months ending May 31, 2022.

6. <u>Estimating Techniques.</u> I&M's overall weighted average fuel cost estimating error during the months of the reconciliation period of December 2021 through May 2022 was an underestimation of approximately 9%. I&M's witness Jason E. Walcutt noted that the primary driver of the higher than forecasted costs during the reconciliation period was the lower than forecasted nuclear generation in the month of May. I&M projected its fuel costs for the billing months of November 2022 through April 2023. I&M's filing demonstrates that the estimates of I&M's prospective average fuel costs for the projected period are reasonable after taking into consideration the difference between I&M's projected and actual fuel cost for the reconciliation period of December 2021 through May 2022. No party presented any evidence to the contrary. Based on the evidence, we find that Applicant's estimating techniques are reasonable and its estimate of fuel costs for November 2022 through April 2023 should be accepted.

7. <u>Wind Power Purchases.</u> Applicant's witness Shelli A. Sloan testified in support of I&M's request for approval of ratemaking treatment for costs related to I&M's wind power purchases. Ms. Sloan testified that I&M is projected to receive energy from the Fowler Ridge phase one and phase two wind farms, the Wildcat wind farm, and the Headwaters wind farm. OUCC witness Eckert testified that he reviewed the settlement agreement and subsequent Order in Cause No. 43328 and that I&M has forecasted the costs of wind power that it will be incurring in the future by using the cost per MWh from the Wind Power Purchase Agreements and has identified the wind power MWhs and costs on separate line items. Pub. Ex. No. 2 at 2. I&M's wind purchases are shown consistent with the Commission's Order in Cause No. 38702 FAC 63 and inclusion of these costs conforms to the Commission's November 28, 2007 Order in Cause No. 43328, the January 6, 2010

Order in Cause No. 43750, the September 21, 2011 Order in Cause No. 44034, and the November 25, 2013 Order in Cause No. 44362. Accordingly, the record supports, and the Commission so finds, that the wind power purchase costs reflected in I&M's filing are reasonable and the Commission therefore approves the ratemaking treatment of such costs.

8. Fuel Cost Adjustment Charges. Attachment 1-C, attached to Pet. Ex. 1, sets forth I&M's actual incurred fuel costs for the reconciliation period. I&M's fuel costs for the reconciliation period were under-recovered, in the amount of $10,903,282, based upon projected fuel costs for those months previously approved by the Commission.

Applicant's total estimated cost of fuel for the billing months November 2022 through April 2023 is $145,501,538 and its total estimated sales are 10,372,403 MWhs. I&M's estimated cost of fuel, as indicated on Applicant's Attachment 1-B, Schedule 1, line 23 of Applicant's Exhibit 1, is therefore 14.028 mills per kWh. Combining the variance factor with the estimated per kWh cost of fuel, the per kWh reduction amount resulting from Ind. Code § 8-1-2-42(d)(3), subtracting the base cost of fuel in Cause No. 45235, and adjusting for Indiana Utility Receipts Tax, results in a proposed total fuel factor of 0.497 mills per kWh.

In accordance with the basing point approved by the Commission in Cause No. 45235 and the evidence presented in this proceeding, we find Applicant is authorized to apply a fuel cost adjustment of 0.497 mills per kWh to Applicant's Indiana retail tariffs for the billing months of November 2022 through April 2023. The typical residential bill for a customer using 1,000 kWh per month will decrease by $0.91 or 0.58% compared to the factor approved in Cause No. 38702 FAC 88 (excluding taxes).

9. Required Reporting. I&M's FAC filing continues to utilize the semi-annual filing practice and such practice was unopposed; accordingly, the Commission has approved a fuel cost factor for a six-month period. However, as required by Ind. Code § 8-1-2-42(c), the OUCC should perform a quarterly review of I&M's books and records pertaining to the cost of fuel and report to the Commission by November 25, 2022. Applicant has agreed to cooperate and provide reasonable support in the OUCC's fulfillment of this requirement.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. In accordance with Ind. Code § 8-1-2-42, the fuel cost adjustment charge set forth in Finding No. 8 above for the billing months of November 2022 through April 2023 is approved.

2. I&M's ratemaking treatment for the cost of wind power purchases pursuant to the Commission's Orders in Cause Nos. 43328, 43750, 44034, and 44362 is approved.

3. Prior to implementing the rate, Applicant shall file the tariff and applicable rate schedules under this Cause for approval by the Commission's Energy Division.

4. This Order shall be effective on and after the date of its approval.

HUSTON, FREEMAN, VELETA, AND ZIEGNER CONCUR; KREVDA ABSENT:

APPROVED: OCT 26 2022

I hereby certify that the above is a true and correct copy of the Order as approved.

________________________________ on behalf of
Dana Kosco
Secretary of the Commission

Commissioner	Yes	No	Not Participating
Huston	√		
Freeman	√		
Krevda	√		
Veleta	√		
Ziegner	√		

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE APPLICATION OF INDIANA MICHIGAN POWER COMPANY FOR AUTHORIZATION OF A FUEL COST ADJUSTMENT FOR ELECTRIC SERVICE APPLICABLE FOR THE BILLING MONTHS OF MAY 2023 THROUGH OCTOBER 2023 AND FOR APPROVAL OF RATEMAKING TREATMENT FOR COST OF WIND POWER PURCHASES PURSUANT TO CAUSE NOS. 43328, 43750, 44034 AND 44362

CAUSE NO. 38702 FAC 90

APPROVED: APR 26 2023

ORDER OF THE COMMISSION

Presiding Officer:
Ann Pagonis, Administrative Law Judge

On January 31, 2023, Indiana Michigan Power Company ("I&M" or "Applicant") filed with the Indiana Utility Regulatory Commission ("Commission") its Verified Application for a Fuel Cost Adjustment for electric service to be applicable during the May 2023 through October 2023 billing months, pursuant to the provisions of Ind. Code § 8-1-2-42, and for approval of I&M's ratemaking treatment of wind power purchase costs. I&M filed its case-in-chief on the same day.

The Indiana Office of Utility Consumer Counselor ("OUCC") filed its case-in-chief on March 7, 2023.

On March 20, 2023, I&M filed its rebuttal testimony.

The Commission conducted an evidentiary hearing in this Cause on April 3, 2023, at 9:30 a.m. in Room 222 of the PNC Center, 101 W. Washington Street, Indianapolis, Indiana. Applicant and the OUCC participated in the hearing. At the hearing, the direct testimony and attachments of Applicant and the OUCC were admitted into evidence without objection.

The Commission, based upon the applicable law and the evidence of record, now finds as follows:

1. **Notice and Jurisdiction.** Proper notice of the public hearing in this Cause was published as provided by law. I&M is an Indiana corporation engaged in rendering electric public utility service in the State of Indiana and is a public utility within the meaning of the Public Service Commission Act, as amended. Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to Applicant's fuel cost charge. Therefore, the Commission has jurisdiction over the Applicant and the subject matter of this proceeding.

2. **Applicant's Request.** In its Verified Application, Applicant seeks Commission approval to implement its proposed fuel adjustment cost during the billing months of May 2023 through October 2023 pursuant to Ind. Code § 8-1-2-42 and I&M's ratemaking treatment of wind power purchase costs. I&M's application continues the semi-annual filing process in place since

1999. Applicant also requests the Commission find that the applicable provisions of Ind. Code § 8-1-2-42 are satisfied.

3. Source of Fuel and Coal Increment Pricing. As a condition of receiving its requested fuel adjustment cost, Applicant must demonstrate compliance with the statutory requirements of Ind. Code § 8-1-2-42(d)(1) by making every reasonable effort to acquire fuel and generate or purchase power, or both, so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. Applicant's witness Jeffrey C. Dial summarized Applicant's long-term coal supply agreements and described I&M's coal purchasing strategy. He discussed why the Applicant renewed the Cook Coal Terminal transloading facility for use during the Reconciliation Period (June 2022 through November 2022) and how it affected the actual cost of coal delivered to the Rockport Plant as compared to forecasted. Mr. Dial explained how Central Appalachian coal prices have increased during the Reconciliation Period, but Powder River Basin coal decreased during the same period. Mr. Dial explained how transportation constraints were experienced by the Applicant and how the Applicant utilized increment pricing to ensure I&M had adequate coal available. I&M will continue to evaluate the need for pricing strategies and will update its testimony regarding the use of such pricing in future FAC proceedings. Applicant's witness Ivan Phung further explained how I&M utilized increment pricing in support of managing each unit's coal inventory. Applicant's witness Keith A. Steinmetz described the major nuclear fuel contracts and actions taken to minimize I&M's nuclear fuel costs.

OUCC witness Gregory T. Guerrettaz discussed I&M's cost of nuclear fuel and coal and how generation can be affected by the coal prices. Mr. Guerrettaz recommended that Applicant provide any communications between the Applicant and/or its affiliates with any coal or transportation company regarding delivery issues as well as require I&M to continue to provide all new Nuclear Fuel Leases, bid results, and invoices related to the next fuel batches at the time when workpapers are provided. OUCC witness Michael D. Eckert discussed how low-cost natural gas has resulted in a decrease in demand for coal-fired electricity, resulting in increased coal supplies (inventories). Mr. Eckert explained how the lack of available coal during the Reconciliation Period has resulted in I&M modifying its Day-Ahead Offer Price to manage the coal inventory and recommended that in the next FAC filing, Applicant: 1) file testimony, schedules, and workpapers to justify the need for, or use of coal increment/decrement pricing; and 2) require Applicant to explain the generation strategy and coal inventory management utilized by I&M with Rockport 2 becoming a merchant plant.

Applicant's evidence demonstrates that it has made every reasonable effort to obtain available fuel or power as economically as possible. Based on the evidence presented, as indicated here and further below, the Commission finds that Applicant is endeavoring to acquire fuel for its internal generation, or purchase power, so as to provide electricity at the lowest fuel cost reasonably possible.

4. Operating Expenses. Ind. Code § 8-1-2-42(d)(2) requires the Commission to find that increases in a utility's fuel cost have been offset by decreases in other expenses. Applicant's fuel expenses for the 12-month period ended November 30, 2022, in the amount of $243,283,000, as reflected on Applicant's Attachment 1-F, Schedule 1, Column 9, Line 38, of Exhibit 1, are more than the corresponding amount determined in Applicant's last base rate order (Cause No. 45576) of $185,803,000 by an amount of $57,480,000. Applicant's filing demonstrates that I&M's actual fuel costs are higher than the fuel cost included in Cause No. 45576. Accordingly, any increases in fuel costs must be offset by decreases in other non-fuel costs. We find that I&M is in compliance with the statutory requirements of Ind. Code § 8-1-2-42(d)(2).

5. Return Earned. Applicant's witness Dona Seger-Lawson explained that pursuant to the Order in Cause No. 45576, I&M is authorized to earn an electric operating income of $296,735,000. That amount (when adjusted for Cause Nos. 44182 and 45245) results in an authorized level for the 12 months ended November 30, 2022, of $291,493,000. According to Applicant's Attachment 1-F, Schedule 1, attached to Exhibit 1, for the 12 months ended November 30, 2022, I&M earned an actual jurisdictional net operating income of $289,648,000. This results in I&M's actual return being less than its authorized return for the most recent 12-month period and the sum of the differentials for the relevant period is also greater than zero, meaning that the Commission should find that the "return" test of Ind. Code § 8-1-2-42(d)(3) is satisfied. Therefore, in accordance with Ind. Code § 8-1-2-42(d)(3) an increase to I&M's FAC factor is necessary.

OUCC witness Guerrettaz affirmed Applicant's conformity with the requirements of Cause No. 38702 FAC 89.

Upon our consideration of the record evidence, the Commission finds I&M has properly determined the authorized operating income for the 12 months ended November 30, 2022, and properly reflected the return authorized in Cause Nos. 44182 and 45245. Thus, by the mechanics of the applicable statute, the Commission finds I&M appropriately calculated and applied the reduction amount to its proposed fuel factor in light of the return earned by I&M during the 12 months ending November 30, 2022.

6. Estimating Techniques. I&M's overall weighted average fuel cost estimating error during the months of the reconciliation period of June through November 2022 was an underestimation of approximately 18%. I&M's witness Bryan S. Owens noted that the primary driver of the higher than forecasted costs during the Reconciliation Period were higher than forecasted system purchases and fuel costs, which were partially offset by higher than forecasted Inter-System sales. I&M projected its fuel costs for the billing months of May 2023 through October 2023. I&M's filing demonstrates that the estimates of I&M's prospective average fuel costs for the projected period are reasonable after taking into consideration the difference between I&M's projected and actual fuel cost for the Reconciliation Period. Based on the evidence, we find that Applicant's estimating techniques are reasonable and its estimate of fuel costs for May 2023 through October 2023 should be accepted.

7. Wind Power Purchases. Applicant's witness Shelli A. Sloan testified in support of I&M's request for approval of ratemaking treatment for costs related to I&M's wind power purchases. Ms. Sloan testified that I&M is projected to receive energy from the Fowler Ridge phase one and phase two wind farms, the Wildcat wind farm, and the Headwaters wind farm. OUCC witness Eckert testified that he reviewed the settlement agreement and subsequent Order in Cause No. 43328 and that I&M has forecasted the costs of wind power that it will be incurring in the future by using the cost per MWh from the Wind Power Purchase Agreements and has identified the wind power MWhs and costs on separate line items. Pub. Ex. No. 2 at 2. I&M's wind purchases are shown consistent with the Commission's Order in Cause No. 38702 FAC 63, and inclusion of these costs conforms to the Commission's November 28, 2007, Order in Cause No. 43328, January 6, 2010 Order in Cause No. 43750, September 21, 2011 Order in Cause No. 44034, and the November 25, 2013 Order in Cause No. 44362. Accordingly, the record supports, and the Commission so finds, that the wind power purchase costs reflected in I&M's filing are reasonable and the Commission therefore approves the ratemaking treatment of such costs.

8. Fuel Cost Adjustment Charges. Attachment 1-C to Applicant's Exhibit 1 sets forth I&M's actual incurred fuel costs for the reconciliation period. I&M's fuel costs for the reconciliation period were under-recovered in the amount of $39,727,905, based upon projected fuel costs for those months previously approved by the Commission.

Applicant's total estimated cost of fuel for the billing months May 2023 through October 2023 is $136,789,839 and its total estimated sales are 10,534,005 MWhs. I&M's estimated cost of fuel, as indicated on Applicant's Attachment 1-B, Schedule 1, line 23 of Exhibit 1, is therefore 12.986 mills per kWh. Combining the variance factor with the estimated per kWh cost of fuel, subtracting the base cost of fuel in Cause No. 45576, and including the Variance Factor from FAC 89, results in a proposed total fuel factor of 4.245 mills per kWh.

In accordance with the basing point approved by the Commission in Cause No. 45576 and the evidence presented in this proceeding, we find Applicant is authorized to apply a fuel cost adjustment of 4.245 mills per kWh to Applicant's Indiana retail tariffs for the billing months of May 2023 through October 2023. The typical residential bill for a customer using 1,000 kWh per month will increase by $3.75 or 2.39% compared to the factor approved in Cause No. 38702 FAC 89 (excluding taxes).

9. Required Reporting. I&M's FAC filing continues to utilize the semi-annual filing practice and such practice was unopposed; accordingly, the Commission approves a fuel cost factor for a six-month period. However, as required by Ind. Code § 8-1-2-42(c), the OUCC should perform a quarterly review of I&M's books and records pertaining to the cost of fuel and report to the Commission by November 22, 2023. Applicant has agreed to cooperate and provide reasonable support in the OUCC's fulfillment of this requirement.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. In accordance with Ind. Code § 8-1-2-42, the fuel cost adjustment charge set forth in Finding No. 8 above for the billing months of May 2023 through October 2023 is approved.

2. I&M's ratemaking treatment for the cost of wind power purchases pursuant to the Commission's Orders in Cause Nos. 43328, 43750, 44034, and 44362 is approved.

3. Prior to implementing the rate, Applicant shall file the tariff and applicable rate schedules under this Cause for approval by the Commission's Energy Division.

4. This Order shall be effective on and after the date of its approval.

HUSTON, FREEMAN, KREVDA, VELETA, AND ZIEGNER CONCUR:

APPROVED: APR 26 2023

I hereby certify that the above is a true and correct copy of the Order as approved.

Dana Kosco
Secretary of the Commission

COMMONWEALTH OF VIRGINIA

STATE CORPORATION COMMISSION

STAFF REPORT

APPALACHIAN POWER COMPANY

FUEL AUDIT REPORT

CASE NOS. PUR-2018-00153, PUR-2019-00157,

PUR-2020-00163, PUR-2021-00205, AND PUR-2022-00139

Prepared By:

Sean M. Welsh

And

Richard W. Michaux, Jr.

Division of Utility Accounting and Finance

DECEMBER 19, 2023

APPALACHIAN POWER COMPANY

STAFF FUEL AUDIT REPORT

FOR THE PERIOD JANUARY 1, 2019, THROUGH DECEMBER 31, 2022

CASE NOS. PUR-2018-00153, PUR-2019-00157, PUR-2020-00163,

PUR-2021-00205, AND PUR-2022-00139

Introduction

On September 15, 2022, Appalachian Power Company ("APCo" or "Company") filed with the State Corporation Commission ("Commission") an application pursuant to § 56-249.6 of the Code of Virginia ("Code") seeking an increase to its fuel factor in Case No. PUR-2023-00139.

On March 6, 2023, the Commission issued an Order Establishing 2022-2023 Fuel Factor[1] in Case No. PUR-2022-00139 that, among other things, directed Commission Staff ("Staff") to commence its audit of the January 1, 2019, to December 31, 2022 period ("Audit Period"). The 2022 Order also directed Staff to monitor the Company's fuel cost recovery on a monthly basis and notify the Commission if there is evidence of a change in the recovery balance that permits the Commission, pursuant to Code § 56-249.6 A 2, to reduce the fuel factor during the current period.[2]

In addition, the 2022 Order directed Staff to investigate and report on, at a minimum, the following with respect to the Company's coal procurement activities during the Audit Period:[3]

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[1] *Application of Appalachian Power Company, To revise its fuel factor*, Case No. PUR-2022-00139, Doc. Con. Cen. No. 230310122, Order Establishing 2022-2023 Fuel Factor (March 6, 2023) ("2022 Order").

[2] *Id.* (Ordering paragraph (5)).

[3] *Id.* at 9.

- Whether APCo complied with its Regulated Fuel Procurement Policy and Procedures Manual;
- The timing and adequacy of APCo's response to market turmoil in mid-2021;
- APCo's actions to obtain performance by contractors with whom APCo had coal supply agreements;
- APCo's ability to maintain coal inventories at minimum target levels; and
- If APCo had the ability to maintain the minimum target level of coal inventory, what additional generation would have been available to APCo.

In accordance with the 2022 Order, Staff conducted its fuel audit of APCo for the Audit Period. The purpose of Staff's audit was to: (1) verify the recovery of fuel costs through the fuel factor rates established pursuant to Code § 56-249.6; (2) verify that the Company's actual fuel expenses are in compliance with APCo's Definitional Framework of Fuel Expenses ("Definitional Framework") approved by the Commission; (3) verify the cumulative recovery balance of fuel costs included in the fuel deferral mechanism on the Company's books as of December 31, 2022; and (4) investigate and report on the coal procurement-related issues identified above. Staff's findings and conclusions regarding the Company's coal procurement prudency, as directed by the Commission's 2022 Order, are addressed in the Pre-filed Testimony of Staff Witness Carr in Case No. PUR-2023-00156.

The Audit Period encompasses fuel factors approved by the Commission, pending Staff's audit of actual fuel expenses, for the cases in Table 1:

Table 1

Case No.	Fuel Factor Rate	Effective Period
PUR-2018-00153[4]	2.547¢/kWh	November 1, 2018 – October 31, 2019
PUR-2019-00157[5]	2.300¢/kWh	November 1, 2019 – October 31, 2020
PUR-2020-00163[6]	1.999¢/kWh	November 1, 2020 – October 31, 2021
PUR-2021-00205[7]	2.300¢/kWh	November 1, 2021 – October 31, 2022
PUR-2022-00139[8]	4.319¢/kWh	November 1, 2022 – October 31, 2023

Each component of Staff's audit is discussed in greater detail below. The results of Staff's audit are presented in the following schedules:

Statement I - Cumulative Fuel Deferral Balance as of December 31, 2022

Statement II - Monthly Virginia Jurisdictional Fuel Factor Expense

Statement III - Reconciliation of Coal included in FERC Account 501 to Amount Included in Fuel Factor Expense

Statement IV - Reconciliation of Oil in FERC Account 501 to Amount Included in Fuel Factor Expense

Statement V - Reconciliation of Natural Gas in FERC Accounts 501 & 547 to Amount Included in Fuel Factor Expense

[4] *Application of Appalachian Power Company, To revise its fuel factor*, Case No. PUR-2018-00153, 2019 S.C.C. Ann. Rept. 273, Order Establishing 2017-2018 Fuel Factor (March 25, 2019) ("2018 Order").

[5] *Application of Appalachian Power Company, To revise its fuel factor*, Case No. PUR-2019-00157, 2020 S.C.C. Ann. Rept. 332-333, Order Establishing 2019-2020 Fuel Factor (Mar. 6, 2020) ("2019 Order").

[6] *Application of Appalachian Power Company, To revise its fuel factor*, Case No. PUR-2020-00163, 2021 S.C.C. Ann. Rept. 268-270, Order Establishing 2020-2021 Fuel Factor (Mar. 3, 2021) ("2020 Order").

[7] *Application of Appalachian Power Company, To revise its fuel factor*, Case No. PUR-2021-00205, 2022 S.C.C. Ann. Rept. 343-345, Order Establishing 2021-2022 Fuel Factor (March 15, 2022) ("2021 Order").

[8] *Application of Appalachian Power Company, To revise its fuel factor*, Case No. PUR-2022-00139, Doc. Con. Cen. No. 238310122, Order Establishing 2022-2023 Fuel Factor (March 6, 2023) ("2022 Order").

<u>Statement VI</u> - Reconciliation of Purchased Power in FERC Account 555 to Amount Included in Fuel Factor Expense

<u>Statement VII</u> - Reconciliation of Off-System Sales in FERC Account 447 to Amount Credited Against Fuel Factor Expense

<u>Statement VIII</u> - Calculation of 75% of Off-System Sales to be Credited Against Fuel Factor Expense – Per Company

<u>Statement IX</u> - Audit Period Jurisdictional Demurrage Expense

Summary of Staff's Conclusions

Based on Staff's audit, Staff concludes the following:

1) Virginia jurisdictional fuel factor revenue recoveries:

Period	Revenue Recoveries (millions)
January 1, 2019 - December 31, 2019	$ 352.1
January 1, 2020 - December 31, 2020	$ 300.6
January 1, 2021 - December 31, 2021	$ 283.1
January 1, 2022 - December 31, 2022	$ 369.2

2) Virginia jurisdictional fuel expenses:

Period	Virginia Jurisdictional Fuel Expense (millions)
January 1, 2019 - December 31, 2019	$ 310.2
January 1, 2020 - December 31, 2020	$ 271.5
January 1, 2021 - December 31, 2021	$ 402.9
January 1, 2022 - December 31, 2022	$ 657.0

3) The Virginia jurisdictional deferred fuel balance reflected on the Company's books as of December 31, 2022, is an under-recovery of $405,720,502.

4) Staff's findings and conclusions regarding the Company's coal procurement prudency, as directed by the Commission's 2022 Order are addressed in the Pre-filed Testimony of Staff Witness Carr in Case No. PUR-2023-00156.

5) The Fuel Monitoring System ("FMS") reports were not entirely consistent with the information filed in APCo's fuel factor cases and recorded on its books during the Audit Period.

6) Staff recommends the Company take steps to improve the accuracy and consistency of its FMS Reports.[9]

7) Staff recommends that Case Nos. PUR-2018-00153, PUR-2019-00157, PUR-2020-00163, PUR-2021-00205 and PUR-2022-00139 be closed.

Fuel Factor Rates and Recoveries for January 2019 through December 2022

As summarized in Table 1, above, there were five Commission-approved fuel factor rates in effect for service rendered during the Audit Period. Staff verified that monthly fuel factor revenue recoveries recorded during each month of the Audit Period reflected that month's billing determinants (i.e., kWh sales) and the fuel factor rates approved by the Commission at that time. As reflected in Columns 3 and 4 of Staff Statement I, the Virginia jurisdictional fuel factor revenue recoveries are presented in Table 2:

[9] Staff notes the accuracy of APCo's fuel recovery position, as provided in the monthly FMS report, is paramount to the Commission's ability to exercise its statutory authority, granted under Code § 56-249.6 A 2, in a timely manner.

Table 2

Year	Fuel Factor Revenue Recovery	Adjustments to Recoveries	Total Revenue Recovery
2019	$ 351,170,259	$ 3,567,503	$ 355,737,762
2020	$ 300,621,846	$ 0	$ 300,621,846
2021	$ 283,168,359	$ 0	$ 283,168,359
2022	$ 369,227,242	$ 0	$ 369,227,242

Background

APCo is an investor-owned electric utility headquartered in Charleston, West Virginia and is a subsidiary of American Electric Power Company, Inc. ("AEP"). The Company provides electricity to approximately 530,000 customers in Virginia with additional customers in its Tennessee and West Virginia service territories. Most of the electricity provided to customers is generated by APCo at power plants located in Ohio, Virginia, and West Virginia. APCo sells excess generated electricity through Off-System Sales ("OSS") and, when necessary, supplements generation with purchased power when needed or economic indicators appear favorable.

Total generating capacity during the Audit Period decreased 5 megawatts ("MW") from 6,686 MW as of January 2019 to 6,681 MW as of December 2022. Generating capacity at APCo's coal-fired and natural gas-fired power plants remained steady at 4,250 MW and 1,646 MW, respectively. The 5 MW decrease to generating capacity occurred at APCo's hydro-generation facilities.[10]

[10] See Statement X.

Annual Fuel Factor Recoveries, Expenses and Deferral Balances

Table 3

Year	**Recoveries** *(in millions)*	**Expenses** *(in millions)*	**Deferral Balance Over/(Under)** *(in millions)*
2019	$ 355.7	$ 310.2	($ 37.2)
2020	$ 300.6	$ 271.5	($ 8.1)
2021	$ 283.1	$ 402.9	($ 127.8)
2022	$ 369.2	$ 647.2	($ 405.7)

Staff audited APCo's coal, oil, and natural gas activities during the Audit Period to determine whether the costs included in the fuel factor were consistent with the Company's Definitional Framework. APCo's fuel factor mechanism is designed to recover fuel-related expenses for coal, natural gas, light oil, and purchased power. Off-system sales were used to offset fuel expenses and the Company did not engage in any fuel-related financial hedging during the Audit Period. Staff's audit examined the following:

1) All balance sheet accounts to which fuel inventories are booked;
2) All income statement accounts to which fuel costs, purchased power expenses, and off-system sales revenue are booked;
3) Fuel related reports and schedules submitted to the Commission during the Audit Period;
4) Source documentation, including third-party invoices and contracts, which were sampled to verify fuel and purchased power expenses reported in February 2019, July 2020, December 2020, August 2021, and June 2022 (collectively "Test Months");

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5) The Company's methodology for allocating costs among jurisdictions; and
6) Any Commission decisions or other significant events impacting the level of fuel expenses recognized during the Audit Period.

The findings from Staff's audit and examination of APCo's fuel reporting and per books records related to fuel expenses, recoveries, and balances are discussed in greater detail below.

Fuel Monitoring System ("FMS") Reports

Pursuant to Code § 56-249.3, APCo submitted FMS reports to the Commission each month during the Audit Period. The FMS reports provide a wide range of actual financial and operational information about the Company's power generation activities.[11] From a fuel accounting perspective, the FMS reports are significant in that they are intended to provide details related to the Company's actual fuel costs and fuel deferral balance on a continual basis. Since the FMS reports represent the fuel cost accounting on a monthly basis, there should be consistency with the information used to calculate the correction factor in the Company's fuel factor proceedings. Thus, auditing and verifying the information contained in the FMS reports are an important part of Staff's audit.

Staff reviewed procurement contracts, tied third-party invoices, and verified calculations to confirm quantities and costs reflected in the FMS reports. Fuel costs and balances in the FMS reports were cross-checked with the Company's books, fuel accounting worksheets, and fuel factor schedules to ensure consistency.

[11] The information presented in the FMS reports is compiled primarily from software called Comtrack and is commonly referred to by the Company as Page 24s.

Staff discovered, and the Company confirmed, that adjustments for coal pile surveys[12] had been mistakenly omitted from the FMS reports after April 2019. In July 2021, the Company also made an adjustment to remove prior period demurrage charges from fuel expense that had been incorrectly included during the period of March 2019 to May 2021.[13] Historically, the Commission has viewed demurrage as a penalty that should not be recovered from customers and removed from fuel expenses in the FMS reports. Most importantly, the Company's January 2022 change to its fuel revenue recognition methodology was not incorporated into its FMS reports prior to the end of the Audit Period.

Overall, Staff believes the FMS Reports, filed by the Company during the Audit Period, contain material errors. Staff's audit and investigation revealed deficiencies with the FMS reports that caused them to be inconsistent with the information presented in the fuel factor cases during the Audit Period. The Company identified and corrected some deficiencies both during and after the Audit Period. However, since the FMS reports did not include the change in methodology for recognizing the amount of fuel revenues, the over/under deferred fuel balances reported during 2022 are incorrect. The Company has not yet corrected its FMS reports' fuel revenues but has stated it is willing to work with Staff to determine a mutually acceptable timeline for completing such revisions. Staff will work with APCo to ensure the Company makes the necessary corrections in a timely manner.

[12] Response to Staff Data Request 4-52. Staff included the effect of the unreported coal pile surveys during the Audit Period in its adjustments to fuel expense in Statement II.

[13] Response to Staff Data Request 5-58.

Coal

During the Audit Period, the Company owned and operated its Amos and Mountaineer coal generation stations consisting of four total generation units capable of producing 4,250 MW. Prior to 2019, the cost of natural gas generation had become often cheaper than coal generation and, in anticipation of more stringent fossil fuel emissions regulations, APCo decided to reduce its number of coal-fired generation units. As a result, the Company retired three of its six coal generation plants and converted one of its coal plants to natural gas, which decreased the Company's total coal generation nameplate capacity by 1,697 MW.

Coal Procurement

The Company procures a majority of its coal through long-term contracts and supplements its remaining coal requirement through spot market purchases. The Company does not purchase coal from an affiliated supplier. The Company awards long-term coal supply contracts following Requests for Proposal ("RFP"), which are publicly provided and electronically transmitted, to all known suppliers. The Company primarily issues public RFPs two to three times annually. Spot market purchases may be made anytime on an as-needed basis up to three years out.

From January 2019 through mid-2021, the Company's cost to procure coal was relatively stable. After mid-2021, APCo's coal supply and procurement costs were negatively impacted by energy commodity market conditions. The effects of the market conditions on APCo's coal procurement program are discussed in Staff witness Carr's testimony filed in Case No. PUR-2023-00156.

Coal Inventory

APCo's coal inventory is maintained on its books in FERC account 151. Coal inventory includes the invoiced costs of coal, freight, switching, demurrage, barging, excise taxes, insurance, and other purchase- and transportation-related costs. Coal inventory levels are maintained on a plant-by-plant basis and are adjusted quarterly based on the judgment of the Company's coal procurement specialists. Staff tied the Company's fuel receipt reports to the amounts recorded to inventory on its books and reviewed supplier invoices for a sampling of shipments within each Test Month.

Staff observed that the April 2019 FMS Report contains the only coal pile survey adjustment reported by the Company during the Audit Period. In response to Staff Data Request 4-52, the Company confirmed that coal pile surveys conducted between May 2019 and December 2022 had not been properly captured in the monthly FMS Reports for that time period.

Coal Expense

APCo records total company coal expense on its books in FERC account 501. The amount of coal expense booked each month reflects (i) the estimated cost of coal in the current month, (ii) an adjustment to reflect the actual cost of coal for the prior month, and (iii) any other prior period adjustments to coal expense. Coal-related expenses not recovered through the fuel factor are booked to a separate sub-account.

Based on its audit, Staff believes that coal expense recorded to FERC account 501 and recovered through the Virginia jurisdictional fuel factor appears to be in compliance with APCo's

Definitional Framework and does not materially misrepresent the Company's actual coal expense.[14]

Light Oil

Oil is used as a start-up fuel and stabilizer in the Company's coal-fired generating units. Light oil represents approximately 3% of the Company's total fuel expense. The Company uses a mix of contracts and spot markets to procure light oil.

Oil Inventory

Oil inventory is maintained on the Company's books in FERC account 151. Oil inventories include commodity and transportation costs. Staff tied the Company's per books inventory for the Test Months to its purchase reports and reviewed inventory adjustments on the Company's FMS reports. Staff's audit and analysis did not discover any discrepancies in the Company's accounting or methodology used to account for fuel oil stock during the Audit Period.

Oil Expense

Oil expense is recorded on a total Company basis in FERC account 501. The Company calculates the weighted-average cost per barrel of oil available for consumption and then uses the estimated quantity of oil burned during the period to calculate the monthly oil expense. Oil expense is recovered through separate jurisdictional fuel factors and booked as a component of total fuel revenues by customer class. Based on its audit, Staff believes that oil expense recorded in accounts 501 and recovered through the Virginia jurisdictional fuel factor comply with the

[14] The FMS misstatements discussed above were limited to those FMS reports and did not affect the expense recorded on the Company's books.

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Company's Definitional Framework. Statement IV reconciles oil expense booked to the general ledger and the amounts recovered through the fuel factor during the Audit Period.

Natural Gas

During the Audit Period, the Company operated eleven natural gas-fired units at three plants with generating capacity of 1,646 MW. The Company purchases all natural gas commodities from the spot market. Natural gas-fired generating units are connected directly to supply pipelines without utilizing storage facilities (other than imbalance inventory services on the pipelines). Natural gas is transported to Ceredo through a contract with the local distributor. Natural gas is delivered to Dresden and Clinch River through both firm and interruptible transportation contracts.

Natural Gas Inventory

APCo maintains an inventory of natural gas in FERC account 151. The natural gas inventory account includes the commodity and transportation costs of surplus natural gas purchased during the month. Staff reviewed the Company's inventory accounting and tied supporting invoices, consumption expense and adjusting entries during the test months to the amounts reflected in the general ledger balances.

Natural Gas Expense

Natural gas expense is recorded in FERC accounts 501 and 547. Unlike the natural gas inventory account, natural gas expenses for Ceredo and Dresden are maintained in separate general ledger accounts. The metered volumes of natural gas flowed into each generating unit is used to determine the cost of natural gas expense booked to the general ledger. Staff tied the natural gas consumption costs in the FMS report to the per books fuel expenses.

Based on its audit, Staff believes that natural gas expense recorded on the books and recovered through the fuel factor appears to comply with APCo's Definitional Framework.

Purchased Power

The Company primarily flows purchased power expense from three sources through the fuel factor: PJM energy purchases, Ohio Valley Electric Corporation, and various wind and solar generator contracts that are typically aggregated as wind purchased power agreements. There are also certain smaller and sporadic purchases, including from small non-utility generators, that flow through the fuel factor. Purchased power expense is recorded in various account 555 sub-accounts. All expenses are recorded on a one-month lag. These accounts also include various non-fuel factor expenses, and occasionally monthly journal entries are aggregated with only part of the entry recovered through the fuel factor.

Staff analyzed purchased power transactions to determine which costs are recoverable under the Commission's Definitional Framework. Statement VI shows purchased power expense by month during the Audit Period. As shown on Statement VI, Staff identified certain discrepancies between the purchased power amounts shown on the FMS filings and amounts recovered through the fuel factor. However, Staff was able to verify that the amounts recovered through the fuel factor tie to the Company's books and accurately represent purchased power costs recoverable under the Definitional Framework.

Based on its audit, Staff believes that purchased power expense recorded on the books and recovered through the fuel factor appears to comply with APCo's Definitional Framework.

Off-System Sales

AEP's generating units were dispatched on an economic basis within PJM to ensure that the System's energy requirements are met at the lowest possible cost. Each hour, the System was then re-dispatched to determine the level of generation from each unit that would have resulted had each OSS not been made. Based on that re-dispatch operation, it can be determined which unit(s) generated energy for OSS, and it is that generation and respective energy cost that is assigned to such sales. This means that the higher cost units are assigned to OSS and the lower cost units are assigned to internal firm power requirements.

APCo included the fuel costs and the offsetting reimbursements in its fuel expense for fuel factor recovery. During the Audit Period, 75% of the margins resulting from OSS were an offset to fuel factor costs.[15]

Staff received and audited a sample of journal entries recording OSS, along with underlying invoices and other documentation supporting the amounts recorded. Staff found that OSS margins during the Audit Period were properly calculated, accounted for, and includable as an offset to fuel factor costs. Statement VII shows OSS by month during the Audit Period. Statement VIII shows the associated OSS margins.

Financial Transmission Rights ("FTRs"), Congestion, and Marginal Line Losses

The Commission found in Case No. PUE-2009-00038 that FTR revenue associated with FTRs received through the PJM Auction Revenue Right process and congestion costs associated with serving native load should be included fully in the Company's fuel factor, rather than included

[15] Credits for OSS margins were an element of base rate cost of service until they were moved to an Off-System Sales Margin Rider on October 2, 2006. On September 1, 2007, before the Audit Period, these margins were moved to the fuel factor with 75% of such margins serving to reduce fuel costs.

in the calculation of OSS margins, of which only 75% is included in the fuel factor.[16] Likewise, the Commission found that "phantom" OSS margins associated with marginal line losses should be included 100% in the fuel factor, rather than in OSS margins. Staff has reviewed the Company's compliance with that order. The Company's FTR revenue, congestion cost, and OSS margin accounting changes as a result of that order appear consistent with the Commission's findings.

Jurisdictional Factors

Jurisdictional factors are calculated each month to allocate total company fuel expense to customers served by APCo.[17] The Company's jurisdictional factor methodology is consistent with the method it has used since the 2009 Order. Staff tied the kWh sales information and jurisdictional factors in the fuel factor filing to the jurisdictional factor calculations during the Audit Period. Based on its audit of the jurisdictional factor calculation for the test months, Staff believes the allocation of fuel expense to Virginia jurisdictional customers during the Audit Period is reasonable and consistent with APCo's Definitional Framework.

Recoveries

The Company records jurisdictional fuel factor recoveries to FERC accounts 440, 442, 444, 445 and 447.[18] Staff verified that the Company's monthly fuel factor recoveries during the Audit

[16] *Application of Appalachian Power Company, To revise its fuel factor pursuant to Va. Code § 56-249.6*, Case No. PUE-2009-00038, 2009 S.C.C. Ann. Rept. 462, 467-69, Order Establishing Fuel Factor (Aug. 3, 2009) ("2009 Order").

[17] Fuel expense is allocated among Virginia retail, Virginia non-jurisdictional, West Virginia and FERC Jurisdictional customers.

[18] Recoveries are recorded in subaccounts 440005 – Residential Fuel Rev, 442013 – Commercial Fuel Rev, 4420016 – Industrial Fuel Rev, 4420019 Affiliated C&I Sales – Fuel Rev, 4440002 Pulic St & Hwy Light Fuel Rev, 4450004 Oth Sales Pulic Auth Fuel Rev and 4470027– Whsal/Muni/Pb Ath Fuel Rev.

Period were consistent with that month's kWh sales[19] and that the Commission-approved fuel factor was applied properly in each billing month. Annual fuel revenues from both the correction factor and in-period factor are shown on Statement I.

Fuel Deferral Balance

The Company reports the actual cumulative fuel deferral balance in the fuel factor filing. The cumulative fuel deferral balance on the Company's books reflects the estimated month-end balance. Under-recovery balances are reflected in account 1823148 – Unrecovered Fuel Cost - VA, while over-recovery balances are reflected in account 2540093 – Over Recovered Fuel Cost - VA. Each month, the Company adjusts the per book cumulative fuel deferral balance to true-up the prior month estimate to actual and to record the current estimated month-end balance. As shown on Statement I, the Company's deferred fuel balance, as of December 31, 2022, reflects an under-recovery of $405,720,199.

Conclusion

Based on its audit of the Company's fuel recoveries and expenses during the period 2019 through 2022, Staff has determined the Company's cumulative deferred fuel balance as of December 31, 2022, is $405,720,199.

[19] Staff tied the in-period Virginia jurisdictional kWh sales to the Virginia jurisdictional kWh sales for determining the Company's jurisdictional factors.

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Statement I

Appalachian Power Company
Virginia Jurisdictional Fuel Deferral Balance - Actual
As of December 31, 2022

Year	Beginning Deferral Balance (Under)/Over	Fuel Recoveries (In-Period and Correction)	Virginia Jurisdictional Fuel Expense	Adjustments to Recoveries	Ending Deferral Balance (Under)/Over
2019	$ (82,733,493)	$ 352,170,259	$ 310,157,944	$ 3,567,503	$ (37,153,675)
2020	$ (37,153,675)	$ 300,621,846	$ 271,537,962	$ -	$ (8,069,791)
2021	$ (8,069,791)	$ 283,168,359	$ 402,877,200	$ -	$ (127,778,633)
2022	$ (127,778,633)	$ 369,227,242	$ 647,168,808	$ -	$ (405,720,199)

Statement II

Appalachian Power Company
Virginia Jurisdictional Fuel Expense - Actual
As of December 31, 2022

Year	Coal Expense	Oil Expense	Natural Gas Expense	Purchased Power Expense	Off-System Sales	25% Off-System Sales Margins	Total Fuel Expense	Adjustments to Fuel Expense	Virginia Jurisdictional Fuel Expense
2019	$ 159,297,872	$ 4,638,893	$ 46,513,297	$ 104,848,760	$ (8,169,144)	$ 2,042,286	$ 309,171,964	$ 985,980	$ 310,157,944
2020	$ 151,684,799	$ 4,950,733	$ 29,967,761	$ 89,261,937	$ (3,530,597)	$ 882,649	$ 273,217,282	$ (1,679,320)	$ 271,537,962
2021	$ 188,583,377	$ 5,031,816	$ 57,932,435	$ 146,640,769	$ (10,106,325)	$ 2,526,581	$ 390,608,652	$ 12,268,548	$ 402,877,200
2022	$ 159,305,345	$ 7,709,337	$ 112,435,081	$ 381,081,653	$ (11,724,542)	$ 2,931,135	$ 651,738,010	$ (4,569,202)	$ 647,168,808

Statement III

Appalachian Power Company
Reconciliation of Coal Expense in FERC Account 501 to Amount Included in Fuel Factor Expense
For the Period January 1, 2019 through December 31, 2022

	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019	Jul 2019	Aug 2019	Sep 2019	Oct 2019	Nov 2019	Dec 2019	Total 2019
Acct 5010001	$ 50,156,967	$ 30,840,647	$ 24,674,097	$ 21,930,690	$ 36,765,581	$ 36,542,491	$ 44,697,525	$ 35,637,331	$ 21,805,934	$ 10,043,365	$ 16,881,842	$ 18,848,623	$ 348,825,092
FMS Report	50,156,946	30,840,643	24,674,093	21,930,688	36,765,581	33,347,532	44,697,525	35,637,331	21,636,226	10,043,365	16,881,842	18,848,623	345,460,395
Difference	$ 21	$ 5	$ 4	$ 2	$ -	$ 3,194,959	$ -	$ -	$ 169,708	$ -	$ -	$ -	$ 3,364,697
Demurrage	21	5	-	-	-	-	-	-	-	-	-	-	26
Residual	$ -	$ -	$ 4	$ 2	$ -	$ 3,194,959	$ -	$ -	$ 169,708	$ -	$ -	$ -	$ 3,364,671
Note						[A] [B]			[A]				
Virginia Jurisdictional Allocator	0.46918	0.46831	0.46380	0.46318	0.44506	0.47726	0.45216	0.45968	0.44840	0.44529	0.46042	0.47239	
Virginia Jurisdictional Expense	$ 23,532,485	$ 14,442,951	$ 11,443,894	$ 10,157,834	$ 16,362,889	$ 15,915,343	$ 20,210,299	$ 16,381,661	$ 9,701,705	$ 4,472,190	$ 7,772,738	$ 8,903,882	$ 159,297,872

	Jan 2020	Feb 2020	Mar 2020	Apr 2020	May 2020	Jun 2020	Jul 2020	Aug 2020	Sep 2020	Oct 2020	Nov 2020	Dec 2020	Total 2020
Acct 5010001	$ 13,225,098	$ 23,931,576	$ 26,469,712	$ 29,078,295	$ 38,040,064	$ 29,846,280	$ 36,585,986	$ 44,260,868	$ 30,152,651	$ 18,817,062	$ 13,050,870	$ 23,050,927	$ 326,509,389
FMS Report	13,225,098	23,931,577	26,469,713	29,078,295	38,040,063	26,936,894	36,585,986	44,260,868	30,152,651	18,817,062	13,050,870	23,704,538	324,253,615
Difference	$ -	$ (1)	$ (1)	$ -	$ 1	$ 2,909,386	$ -	$ -	$ -	$ -	$ -	$ (653,611)	$ 2,255,774
Demurrage	-	-	-	-	-	-	-	-	-	-	-	-	-
Residual	$ -	$ (1)	$ (1)	$ -	$ 1	$ 2,909,386	$ -	$ -	$ -	$ -	$ -	$ (653,611)	$ 2,255,774
Note						[A]						[A]	
Virginia Jurisdictional Allocator	0.46134	0.46783	0.46049	0.45673	0.46983	0.47353	0.47580	0.45022	0.48138	0.46087	0.46875	0.49150	
Virginia Jurisdictional Expense	$ 6,101,280	$ 11,195,886	$ 12,188,906	$ 13,280,959	$ 17,872,211	$ 12,755,427	$ 17,407,685	$ 19,926,951	$ 14,514,943	$ 8,672,257	$ 6,117,608	$ 11,650,686	$ 151,684,799

	Jan 2021	Feb 2021	Mar 2021	Apr 2021	May 2021	Jun 2021	Jul 2021	Aug 2021	Sep 2021	Oct 2021	Nov 2021	Dec 2021	Total 2021
Acct 5010001	$ 43,693,776	$ 47,718,239	$ 21,590,993	$ 17,092,277	$ 35,741,499	$ 47,634,054	$ 50,138,371	$ 48,145,174	$ 32,066,127	$ 7,578,335	$ 1,638,801	$ 39,416,447	$ 392,454,093
FMS Report	43,693,776	47,718,239	21,590,993	17,092,277	36,749,502	47,601,022	50,100,296	48,115,395	33,122,435	7,577,308	1,638,587	40,136,895	395,136,725
Difference	$ -	$ -	$ -	$ -	$ (1,008,003)	$ 33,032	$ 38,075	$ 29,779	$ (1,056,308)	$ 1,027	$ 214	$ (720,448)	$ (2,682,632)
Demurrage	-	-	-	-	-	33,032	38,075	29,778	12,673	1,028	214	10,538	125,339
Residual	$ -	$ -	$ -	$ -	$ (1,008,003)	$ -	$ -	$ 1	$ (1,068,981)	$ (1)	$ -	$ (730,987)	$ (2,807,971)
Note					[A]				[A]			[A]	
Virginia Jurisdictional Allocator	0.47873	0.49014	0.46800	0.47952	0.46879	0.48675	0.46944	0.47737	0.47082	0.46639	0.47345	0.48020	
Virginia Jurisdictional Expense	$ 20,830,265	$ 23,388,713	$ 10,104,477	$ 8,196,140	$ 17,227,909	$ 23,169,797	$ 23,519,033	$ 22,968,894	$ 15,594,705	$ 3,533,966	$ 775,781	$ 19,273,697	$ 188,583,377

	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Total 2022
Acct 5010001	$ 43,828,522	$ 28,471,896	$ 9,341,113	$ 8,105,721	$ 12,953,841	$ 19,032,819	$ 51,847,312	$ 55,768,604	$ 22,191,253	$ 15,416,789	$ 21,792,006	$ 47,301,528	$ 336,051,403
FMS Report	43,816,651	28,466,785	12,311,441	8,105,115	12,952,985	19,030,885	51,827,612	55,748,398	22,182,829	14,287,001	21,778,535	45,686,030	336,194,267
Difference	$ 11,871	$ 5,111	$ (2,970,328)	$ 606	$ 856	$ 1,934	$ 19,700	$ 20,206	$ 8,424	$ 1,129,788	$ 13,471	$ 1,615,498	$ (142,864)
Demurrage	11,872	5,110	1,437	606	856	1,935	19,700	20,207	8,424	11,640	13,470	16,154	111,411
Residual	$ -	$ -	$ (2,971,765)	$ -	$ -	$ (1)	$ -	$ (1)	$ -	$ 1,118,148	$ -	$ 1,599,343	$ (254,276)
Note			[A]							[A]		[A]	
Virginia Jurisdictional Allocator	0.478654	0.474162	0.466773	0.472034	0.478896	0.476171	0.477065	0.464715	0.462880	0.478043	0.471994	0.481273	
Virginia Jurisdictional Expense	$ 20,973,015	$ 13,497,868	$ 5,746,648	$ 3,825,890	$ 6,203,133	$ 9,061,956	$ 24,725,140	$ 25,907,117	$ 10,267,988	$ 6,829,801	$ 10,279,338	$ 21,987,453	$ 159,305,345

Notes: [A] Coal pile survey adjustment excluded from FMS Report, Staff Set 2-19.
[B] Erroneous charges included in Account 5010001, corrected July 2023, Staff Set 3-45.

Statement IV

Appalachian Power Company
Reconciliation of Oil Expense in FERC Account 501 to Amount Included in Fuel Factor Expense
For the Period January 1, 2019 through December 31, 2022

	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019	Jul 2019	Aug 2019	Sep 2019	Oct 2019	Nov 2019	Dec 2019	Total 2019
Acct 5010019	$ 298,456	$ 408,976	$ 714,516	$ 806,788	$ 825,444	$ 630,590	$ 1,277,804	$ 1,075,071	$ 724,872	$ 968,344	$ 1,218,971	$ 1,152,682	$ 10,102,513
FMS Report	$ 298,456	$ 408,976	$ 714,516	$ 806,788	$ 825,444	$ 630,590	$ 1,277,803	$ 1,075,071	$ 724,872	$ 968,343	$ 1,218,971	$ 1,152,682	$ 10,102,512
Difference	$ -	$ -	$ -	$ -	$ -	$ -	$ 1	$ -	$ -	$ 1	$ -	$ -	$ 1
Virginia Jurisdictional Allocator	0.46918	0.46831	0.46380	0.46318	0.44506	0.47726	0.45216	0.45968	0.44840	0.44529	0.46042	0.47239	
Virginia Jurisdictional Expense	$ 140,029	$ 191,527	$ 331,394	$ 373,687	$ 367,372	$ 300,953	$ 577,768	$ 494,185	$ 325,033	$ 431,192	$ 561,239	$ 544,514	$ 4,638,893

	Jan 2020	Feb 2020	Mar 2020	Apr 2020	May 2020	Jun 2020	Jul 2020	Aug 2020	Sep 2020	Oct 2020	Nov 2020	Dec 2020	Total 2020
Acct 5010019	$ 1,974,784	$ 2,301,114	$ 408,865	$ 517,858	$ 318,556	$ 257,609	$ 1,248,161	$ 977,577	$ 754,946	$ 152,258	$ 937,856	$ 731,432	$ 10,581,015
FMS Report	$ 1,974,789	$ 2,301,114	$ 408,866	$ 517,859	$ 318,556	$ 257,608	$ 1,248,161	$ 977,577	$ 754,946	$ 152,259	$ 937,856	$ 731,432	$ 10,581,023
Difference	$ (5)	$ -	$ (1)	$ (1)	$ -	$ 1	$ -	$ -	$ -	$ (1)	$ -	$ -	$ (8)
Virginia Jurisdictional Allocator	0.46134	0.46783	0.46049	0.45673	0.46983	0.47353	0.47580	0.45022	0.48138	0.46087	0.46875	0.49150	
Virginia Jurisdictional Expense	$ 911,051	$ 1,076,528	$ 188,277	$ 236,522	$ 149,666	$ 121,985	$ 593,878	$ 440,121	$ 363,417	$ 70,172	$ 439,621	$ 359,496	$ 4,950,733

	Jan 2021	Feb 2021	Mar 2021	Apr 2021	May 2021	Jun 2021	Jul 2021	Aug 2021	Sep 2021	Oct 2021	Nov 2021	Dec 2021	Total 2021
Acct 5010019	$ 784,467	$ 317,452	$ 217,506	$ 1,420,225	$ 974,953	$ 1,313,915	$ 228,604	$ 1,098,132	$ 377,051	$ 188,352	$ 688,283	$ 2,915,566	$ 10,524,505
FMS Report	$ 784,467	$ 317,452	$ 217,506	$ 1,420,225	$ 974,953	$ 1,313,915	$ 228,604	$ 1,098,132	$ 377,051	$ 188,352	$ 688,283	$ 2,915,566	$ 10,524,506
Difference	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1)
Virginia Jurisdictional Allocator	0.47673	0.49014	0.46800	0.47952	0.46879	0.48675	0.46944	0.47737	0.47082	0.46639	0.47345	0.48020	
Virginia Jurisdictional Expense	$ 373,981	$ 155,597	$ 101,792	$ 681,031	$ 457,051	$ 639,548	$ 107,316	$ 524,216	$ 177,523	$ 87,845	$ 325,864	$ 1,400,052	$ 5,031,816

	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Total 2022
Acct 5010019	$ 479,091	$ 693,503	$ 155,372	$ 776,343	$ 1,549,551	$ 2,504,444	$ 1,830,482	$ 924,545	$ 1,759,823	$ 225,028	$ 3,837,123	$ 1,540,533	$ 16,275,838
FMS Report	$ 479,092	$ 693,502	$ 155,371	$ 776,343	$ 1,549,551	$ 2,504,444	$ 1,830,482	$ 924,545	$ 1,759,823	$ 225,028	$ 3,837,123	$ 1,540,534	$ 16,275,838
Difference	$ (1)	$ 1	$ 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1)	$ -

Statement V

Appalachian Power Company
Reconciliation of Natural Gas Expense in FERC Accounts 501 & 547 to Amount Included in Fuel Factor Expense
For the Period January 1, 2019 through December 31, 2022

	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019	Jul 2019	Aug 2019	Sep 2019	Oct 2019	Nov 2019	Dec 2019	Total 2019
Acct 5010020	$ 306,531	$ 374,900	$ 335,026	$ 709,225	$ 251,049	$ 679,253	$ 5,750,433	$ 1,117,709	$ 1,760,065	$ 1,244,067	$ 1,031,732	$ (5,149)	$ 13,554,840
Acct 5010021	-	-	-	-	-	-	-	-	-	-	-	-	-
Acct 5010034	440,631	440,631	440,631	440,631	440,631	440,631	440,631	440,631	440,631	440,631	440,631	440,631	5,287,572
Acct 5010035	301,525	301,525	301,525	301,525	301,525	301,525	301,525	301,525	301,525	301,525	301,525	301,525	3,618,300
Acct 5010036	9,118,422	7,091,883	8,267,478	5,435,480	4,866,648	5,364,161	5,621,905	4,893,442	3,241,306	3,219,328	6,294,312	5,480,743	68,898,108
Acct 5010037	-	-	-	-	-	-	-	-	-	-	-	-	-
Acct 5010040	-	-	-	-	-	-	-	-	-	-	-	-	-
Acct 5470001	629,456	209,900	594,569	288,494	68,451	445,227	948,472	967,124	1,416,955	2,813,898	1,127,053	22,525	9,532,121
Acct 5470003	-	2,514	6,872	4,018	1,026	7,324	6,000	6,000	6,000	23,122	55,564	17,342	135,781
Acct 5470005	-	-	-	-	-	-	-	-	-	-	-	-	-
FMS Report	10,796,564	8,424,352	9,946,101	7,179,364	5,929,329	7,238,120	13,068,965	7,726,430	7,166,481	8,042,572	9,250,817	6,257,617	101,026,712
Difference	$ -	$ -	$ -	$ 8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10
Virginia Jurisdictional Allocator	0.46918	0.46831	0.46380	0.46318	0.44506	0.47726	0.45216	0.45968	0.44840	0.44529	0.46042	0.47239	
Virginia Jurisdictional Expense	$ 5,065,500	$ 3,945,200	$ 4,613,022	$ 3,325,331	$ 2,638,907	$ 3,454,443	$ 5,909,224	$ 3,551,662	$ 3,213,457	$ 3,581,261	$ 4,259,261	$ 2,956,029	$ 46,513,297

	Jan 2020	Feb 2020	Mar 2020	Apr 2020	May 2020	Jun 2020	Jul 2020	Aug 2020	Sep 2020	Oct 2020	Nov 2020	Dec 2020	Total 2020
Acct 5010020	$ 95,185	$ 29,826	$ 17,731	$ 8,697	$ 215,868	$ 1,218,608	$ 2,807,878	$ 1,140,095	$ 437,368	$ 180,886	$ 21,065	$ 25,821	$ 6,199,028
Acct 5010021	-	-	-	-	-	-	-	-	11,085	-	19,996	5,641	36,722
Acct 5010034	97,103	425,959	425,959	425,959	425,959	425,959	425,959	425,959	425,959	425,959	425,959	425,959	4,782,652
Acct 5010035	301,525	301,525	301,525	301,525	301,525	301,525	299,586	301,525	301,525	301,525	301,525	301,525	3,616,361
Acct 5010036	5,087,039	4,601,064	4,239,133	2,627,869	3,524,384	3,634,309	3,694,889	3,389,854	3,126,654	2,289,860	3,244,420	5,737,365	43,196,841
Acct 5010037	178,157	-	-	-	134,544	(901)	163,954	147,076	140,745	115,456	198,994	186,679	1,264,704
Acct 5010040	-	-	-	-	(6,996)	2,007	1,622	(185)	(101)	(54,000)	-	(212)	(57,864)
Acct 5470001	702	590	(616)	1,056	90,187	184,959	789,223	283,569	28,421	477,630	191,646	636,311	2,633,678
Acct 5470003	707	7	13	4	10	1,643	3,919	15,584	5,138	517	8,953	52,164	88,658
Acct 5470005	-	-	7,600	-	-	-	-	-	-	-	-	-	7,600
FMS Report	5,760,419	5,358,971	4,991,345	3,365,109	4,692,477	5,766,102	8,135,408	5,703,662	4,476,896	3,791,832	4,412,557	7,371,254	63,826,032
Difference	$ -	$ -	$ -	$ -	$ (6,996)	$ 2,006	$ 1,622	$ (185)	$ (102)	$ (54,000)	$ -	$ -	$ (57,654)
Note					[A]	[A]	[A]	[A]	[A]	[A]			
Virginia Jurisdictional Allocator	0.46134	0.46783	0.46049	0.45673	0.46983	0.47353	0.47580	0.45022	0.48138	0.46087	0.46873	0.49150	
Virginia Jurisdictional Expense	$ 2,657,517	$ 2,507,082	$ 2,298,440	$ 1,536,950	$ 2,204,648	$ 2,730,422	$ 3,870,843	$ 2,567,880	$ 2,155,097	$ 1,747,549	$ 2,068,391	$ 3,622,942	$ 28,967,761

	Jan 2021	Feb 2021	Mar 2021	Apr 2021	May 2021	Jun 2021	Jul 2021	Aug 2021	Sep 2021	Oct 2021	Nov 2021	Dec 2021	Total 2021
Acct 5010020	15,606	47,909	10,378	304,855	975,333	898,772	588,774	1,610,240	46,503	543,861	2,101,284	110,611	$ 7,254,131
Acct 5010021	-	-	-	16,580	-	-	20,579	8,490	-	-	-	-	45,648
Acct 5010034	424,042	424,042	424,042	424,042	424,042	424,042	424,042	424,042	424,042	424,042	424,042	424,042	5,088,504
Acct 5010035	301,525	301,525	301,525	301,525	301,525	301,525	300,365	301,525	301,525	301,525	301,525	301,525	3,617,140
Acct 5010036	6,549,008	8,850,089	6,031,473	3,317,407	6,059,744	6,085,380	7,661,875	9,405,986	3,320,732	2,067,448	14,291,101	11,435,607	85,073,850
Acct 5010037	191,694	175,380	164,796	89,604	138,972	152,930	133,037	144,524	39,815	23,562	209,769	138,262	1,622,545
Acct 5010040	45,779	(543)	(116)	48,182	5,722	1,000	(419)	4,529	4,789	12,065	(7,875)	(15,182)	97,931
Acct 5470001	107,952	4,074,871	142,008	549,184	441,293	1,554,600	1,395,401	2,063,280	703,282	3,091,169	3,811,946	693,007	18,617,993
Acct 5470003	7,048	1,517	13,590	1,080	8,183	6,109	18,938	14,590	18,754	4,952	21,697	28,084	144,543
Acct 5470005	-	-	-	-	-	-	-	-	-	-	-	-	-
FMS Report	7,642,635	13,874,991	7,087,698	5,052,459	8,354,816	9,424,358	10,542,591	13,977,206	4,859,445	6,458,625	21,153,488	13,135,955	121,564,285
Difference	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Virginia Jurisdictional Allocator	0.47673	0.49014	0.46800	0.47952	0.46879	0.48673	0.46944	0.47737	0.47082	0.46639	0.47345	0.48020	
Virginia Jurisdictional Expense	$ 3,643,506	$ 6,800,716	$ 3,317,006	$ 2,422,770	$ 3,916,679	$ 4,587,306	$ 4,949,103	$ 6,672,313	$ 2,287,924	$ 3,012,225	$ 10,015,013	$ 6,307,872	$ 57,932,435

	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Total 2022
Acct 5010020	(94,911)	254,674	27,218	15,295	2,194,681	1,251,860	2,464,060	813,228	651,582	259,035	1,080,251	7,234,968	$ 16,151,942
Acct 5010021	-	-	-	14,700	(263)	1,035	-	-	32,331	-	32,435	(32,435)	48,003
Acct 5010034	422,027	422,027	422,027	422,027	422,027	422,027	422,027	422,027	422,027	422,027	422,027	422,027	5,064,324
Acct 5010035	301,525	301,525	301,525	755,733	1,074,337	763,632	760,695	763,632	763,632	763,632	763,632	778,587	8,092,088
Acct 5010036	10,456,392	13,077,944	10,450,799	11,830,611	11,138,474	19,577,890	17,609,724	20,663,834	16,952,340	12,529,707	12,702,526	16,565,714	173,555,955
Acct 5010037	223,563	173,423	136,330	(200,643)	14,469	17,407	26,520	27,302	21,671	23,572	26,721	35,928	526,262
Acct 5010040	19,993	(2,289)	555	10,760	(21,241)	(1,072)	(52,762)	(30,592)	10,061	(1,086)	429	(172,450)	(239,693)
Acct 5470001	1,013,113	663,148	1,269,421	2,081,346	4,141,924	6,042,783	7,247,704	3,776,565	707,559	691,588	896,950	4,131,549	32,663,649
Acct 5470003	7,310	9,110	4,320	9,928	12,018	19,905	31,027	38,488	14,824	7,599	5,007	6,000	165,536
Acct 5470005	-	-	-	-	-	-	-	-	-	-	-	1,251,832	1,251,832
FMS Report	12,349,011	14,899,563	12,612,194	14,939,758	18,976,425	28,095,467	28,508,995	26,474,483	19,576,228	14,696,074	15,929,977	30,221,721	237,279,896
Difference	$ -	$ -	$ 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1
Virginia Jurisdictional Allocator	0.478654	0.474162	0.466773	0.472034	0.478896	0.476171	0.477065	0.464715	0.462880	0.478043	0.471994	0.481273	
Virginia Jurisdictional Expense	$ 5,910,904	$ 7,064,807	$ 5,887,032	$ 7,052,074	$ 9,087,734	$ 13,378,247	$ 13,600,644	$ 12,303,089	$ 9,061,444	$ 7,025,355	$ 7,518,854	$ 14,544,898	$ 112,435,081

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Statement VI

Appalachian Power Company
Reconciliation of Purchased Power Expense in Net Energy Report to Amount Included in Fuel Factor Expense
For the Period January 1, 2019 through December 31, 2022

	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019	Jul 2019	Aug 2019	Sep 2019	Oct 2019	Nov 2019	Dec 2019	Total 2019
Net Purchased Power - NER	$ 9,951,349	$ 19,883,779	$ 31,601,799	$ 18,621,166	$ 6,673,680	$ 2,942,486	$ (1,140,685)	$ 12,395,225	$ 26,301,381	$ 31,207,891	$ 36,410,444	$ 32,971,662	$ 227,820,175
FMS Report	9,951,349	19,883,779	31,601,799	18,621,166	6,673,680	2,942,486	(1,140,685)	12,395,225	26,301,381	31,207,891	36,410,444	32,971,662	227,820,175
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Virginia Jurisdictional Allocator	0.46918	0.46831	0.46380	0.46318	0.44506	0.47726	0.45216	0.45968	0.44840	0.44529	0.46042	0.47239	
Virginia Jurisdictional Expense	$ 4,668,944	$ 9,311,753	$ 14,656,978	$ 8,624,933	$ 2,970,188	$ 1,404,322	$ (515,769)	$ 5,697,800	$ 11,793,565	$ 13,896,499	$ 16,764,097	$ 15,575,450	$ 104,848,760

	Jan 2020	Feb 2020	Mar 2020	Apr 2020	May 2020	Jun 2020	Jul 2020	Aug 2020	Sep 2020	Oct 2020	Nov 2020	Dec 2020	Total 2020
Net Purchased Power - NER	$ 41,300,262	$ 23,382,492	$ 14,926,740	$ 6,585,813	$ (3,509,346)	$ 7,586,528	$ 10,380,898	$ 976,145	$ 8,839,772	$ 21,126,165	$ 26,048,009	$ 32,276,458	$ 189,919,935
FMS Report	41,300,262	23,382,492	14,926,740	6,585,813	(3,509,346)	7,586,528	10,380,898	976,145	8,839,772	21,126,165	26,048,009	32,276,458	189,919,935
	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Virginia Jurisdictional Allocator	0.46134	0.46783	0.46049	0.45673	0.46983	0.47353	0.47580	0.45022	0.48138	0.46087	0.46875	0.49150	
Virginia Jurisdictional Expense	$ 19,053,504	$ 10,939,008	$ 6,873,540	$ 3,007,945	$ (1,648,782)	$ 3,592,448	$ 4,939,252	$ 439,476	$ 4,255,307	$ 9,736,458	$ 12,210,030	$ 15,863,750	$ 89,261,937

	Jan 2021	Feb 2021	Mar 2021	Apr 2021	May 2021	Jun 2021	Jul 2021	Aug 2021	Sep 2021	Oct 2021	Nov 2021	Dec 2021	Total 2021
Net Purchased Power - NER	$ 11,676,282	$ 807,014	$ 23,198,220	$ 26,270,934	$ 2,414,047	$ (5,422,803)	$ (2,226,752)	$ (1,960,509)	$ 29,153,752	$ 94,283,537	$ 112,576,532	$ 20,416,846	$ 310,187,101
FMS Report	11,676,282	807,014	23,198,220	26,270,934	2,414,047	(5,422,803)	(2,145,377)	(1,879,134)	29,311,252	94,446,287	112,734,032	20,579,596	310,990,351
	$ -	$ -	$ -	$ -	$ -	$ -	$ (81,375) [A]	$ (81,375) [A]	$ (157,500) [A]	$ (162,750) [A]	$ (157,500) [A]	$ (162,750) [A]	$ (803,250)
Virginia Jurisdictional Allocator	0.47673	0.49014	0.46800	0.47952	0.46879	0.48675	0.46944	0.47737	0.47082	0.46639	0.47345	0.48020	
Virginia Jurisdictional Expense	$ 5,566,469	$ 395,552	$ 10,388,656	$ 12,597,517	$ 1,131,688	$ (2,639,549)	$ (1,007,124)	$ (897,044)	$ 13,800,324	$ 44,048,615	$ 53,373,364	$ 9,882,302	$ 146,640,769

	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Total 2022
Net Purchased Power - NER	$ 46,839,263	$ 52,076,982	$ 72,904,651	$ 88,450,848	$ 103,065,320	$ 99,580,289	$ 21,243,160	$ 13,058,874	$ 82,646,973	$ 70,687,829	$ 60,668,005	$ 94,321,480	$ 805,543,673
FMS Report	47,002,013	52,223,982	73,067,401	88,608,348	103,228,070	99,580,289	21,243,160	13,058,874	82,646,973	69,088,509	59,612,788	94,361,653	803,722,059
	$ (162,750) [A]	$ (147,000) [A]	$ (162,750) [A]	$ (157,500) [A]	$ (162,750) [A]	$ -	$ -	$ -	$ -	$ 1,599,320 [B]	$ 1,055,218 [B]	$ (40,173) [B]	$ 1,821,615
Virginia Jurisdictional Allocator	0.478654	0.474162	0.466773	0.472034	0.478896	0.476171	0.477065	0.464715	0.462880	0.478043	0.471994	0.481273	
Virginia Jurisdictional Expense	$ 22,497,702	$ 24,762,628	$ 34,105,890	$ 41,826,153	$ 49,435,510	$ 47,417,246	$ 10,134,368	$ 6,068,655	$ 38,255,631	$ 33,027,278	$ 28,136,878	$ 45,413,716	$ 381,081,653

Notes: A] Certain solar excluded from FMS Report.
[B] Certain solar and net hedging activity excluded from FMS Report.

Appalachian Power Company
Reconciliation of Off-Systems Sales Expense in FERC Account 447 to Amount Included in Fuel Factor Expense
For the Period January 1, 2019 through December 31, 2022

	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019	Jul 2019	Aug 2019	Sep 2019	Oct 2019	Nov 2019	Dec 2019	Total 2019
4470001	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4470002	271,432	437,829	366,777	201,411	98,587	80,880	590,230	154,651	(34,889)	75,923	(224,821)	(3,542,705)	(1,524,696)
4470006	(3,468,837)	(3,022,362)	(3,171,868)	(2,454,298)	(2,601,534)	(5,552,323)	(7,551,346)	(6,875,866)	(5,816,389)	(4,600,892)	(5,768,508)	(6,030,932)	(56,915,155)
4470010	4,366,507	3,360,788	3,788,247	2,911,387	3,019,273	4,254,697	6,814,270	5,585,249	5,298,840	4,660,893	5,525,897	4,944,232	54,530,278
4470081	-	-	-	16,054	3,171	40,705	-	-	-	-	-	-	59,931
4470082	565,358	708,408	55,725	1,450,872	(646,475)	1,330,644	686,774	1,310,304	898,319	939,873	994,216	1,305,893	9,599,910
4470089	(1,504,625)	(951,117)	253,508	(242,581)	(433,161)	(334,555)	(3,483,075)	679,155	214,749	4,753	376,377	2,220,649	(3,199,925)
4470098	7,893	2,307	405	(302)	10,731	(5,834)	66,962	15,980	12,104	74	(86,356)	1,539	25,504
4470099	(167,892)	(151,644)	(167,892)	(162,476)	(167,892)	(61,801)	(75,535)	7,083	(48,302)	(42,448)	(46,839)	(42,447)	(1,128,085)
4470106	-	-	-	-	407	656	199	-	-	-	-	-	1,262
4470107	4	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(17)
4470110	(96)	-	(65)	5	0	(49)	60	(70)	(130)	-	135	84	(127)
4470112	(218,085)	(200,262)	(208,546)	(48,907)	(207,165)	(300,994)	(324,486)	(161,125)	5,984	-	(245,539)	(3,589)	(1,912,714)
4470115	2,234	4,784	8,521	(127)	493	62	4,768	(699)	(4,014)	18	(1,123)	3,456	18,372
4470124	-	-	-	-	2,917	(2,917)	-	-	-	-	-	-	-
4470126	158,988	(61,307)	(3,182)	(28,547)	(156,789)	(86,838)	103,856	(58,279)	(37,378)	(50,852)	(41,296)	(25,512)	(287,138)
4470131	198,397	167,981	205,153	47,087	197,099	264,390	279,269	141,588	791	13	254,986	172	1,756,925
4470143	(1,078,059)	(1,716,385)	62,063	(43,367)	(281,014)	(1,368,221)	(413,002)	(551,931)	35,602	11	(69,566)	(1,354,594)	(6,778,464)
4470151	(924,664)	(790,432)	(727,210)	(546,000)	(550,154)	(989,050)	(1,404,377)	(1,247,804)	(1,177,451)	(913,216)	(1,038,484)	(1,134,583)	(11,443,426)
4470206	(112,879)	(67,751)	(17,126)	(12,515)	(62,976)	(69,969)	(199,883)	(67,656)	(14,475)	(6,585)	(13,454)	259,734	(385,534)
4470209	423,747	252,576	45,486	28,639	274,548	287,181	617,664	165,873	35,751	16,458	37,925	20,098	2,205,947
4470214	(735)	(8,520)	(2,692)	(704)	(4,246)	(10,240)	(385,063)	(526,236)	(79,062)	(28,454)	(6,865)	(2,553)	(1,055,371)
4470215	(1,406)	5,570	1,189	302	1,928	3,612	107,307	165,778	40,472	18,569	5,138	1,166	349,626
4470220	(85,633)	(87,955)	(76,305)	(37,973)	(168,598)	(261,192)	(220,522)	(276,233)	(120,788)	(25,902)	(49,283)	(64,602)	(1,474,985)
4470221	(6,838)	(6,004)	(10,432)	(15,471)	(3,961)	(15,809)	(29,417)	(6,166)	-	(185)	(139)	(100)	(94,521)
4470222	(3,356)	(544,171)	-	-	-	-	(54,235)	(366,084)	(6,884)	-	-	(32,780)	(1,007,510)
5550039	752	3,173	(128)	1,161	(1,552)	(2,356)	1,362	(2,273)	(848)	(1,168)	(1,144)	(462)	(3,482)
5550099	-	-	-	-	-	(614)	-	-	-	-	-	-	(614)
5570007	-	-	-	-	-	-	-	-	-	-	-	-	-
5614000	70,615	44,718	3,719	17,734	49,240	58,724	99,072	40,967	16,729	8,192	15,867	12,873	438,449
5614008	4,248	5,969	14,991	3,847	6,129	4,171	5,505	3,035	2,867	3,559	7,826	6,086	68,233
5618000	23,848	12,091	2,167	4,746	13,240	15,823	24,494	10,059	4,216	2,400	4,542	3,716	121,342
5757000	59,506	38,920	5,838	15,956	44,834	54,306	85,578	34,081	13,632	7,138	13,716	11,633	385,138
Total Off-System Sales	$ (1,419,575)	$ (2,562,800)	$ 428,340	$ 1,105,930	$ (1,562,921)	$ (2,666,912)	$ (4,653,574)	$ (1,826,622)	$ (760,558)	$ 68,172	$ (356,796)	$ (3,443,530)	$ (17,650,846)
75% of Total Off-System Sales	(1,064,681)	(1,922,100)	321,255	829,448	(1,172,191)	(2,000,184)	(3,490,180)	(1,369,966)	(570,418)	51,129	(267,597)	(2,582,648)	(13,238,134)
FMS Report	(1,064,681)	(1,922,100)	321,255	829,448	(1,172,191)	(2,000,184)	(3,490,180)	(1,369,966)	(570,418)	51,129	(267,597)	(2,582,648)	(13,238,134)
Difference	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Appalachian Power Company
Reconciliation of Off-Systems Sales Expense in FERC Account 447 to Amount Included in Fuel Factor Expense
For the Period January 1, 2015 through December 31, 2022

	Jan 2020	Feb 2020	Mar 2020	Apr 2020	May 2020	Jun 2020	Jul 2020	Aug 2020	Sep 2020	Oct 2020	Nov 2020	Dec 2020	Total 2020
4470001	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4470002	558,853	(369,453)	(324,854)	(204,571)	(242,493)	(62,423)	210,436	287,688	7,372	(420,450)	(630,456)	194,135	(996,216)
4470006	(6,347,802)	(5,779,745)	(4,827,156)	(4,233,840)	(4,181,713)	(1,337,036)	(1,672,332)	(1,561,202)	(1,091,756)	(1,037,844)	(1,147,929)	(1,122,395)	(34,340,750)
4470010	6,260,850	4,480,322	3,630,711	3,200,645	2,876,916	927,337	1,282,217	1,156,558	771,778	743,745	881,723	889,020	27,101,823
4470081	-	-	-	-	-	-	-	-	-	-	-	-	-
4470082	2,284,103	2,365,373	2,210,424	1,800,792	1,778,815	526,415	449,394	218,140	441,010	437,834	294,526	93,804	12,900,629
4470089	337,003	425,335	374,355	947,610	2,054,711	325,044	(678,058)	(2,087,433)	73,251	460,252	658,014	(89,988)	2,800,096
4470098	854	1,160	(134)	3,345	17,130	23,725	35,522	45,309	21,026	5,538	2,900	7,886	164,259
4470099	(46,838)	(48,360)	(51,258)	(49,795)	(46,868)	(173,960)	(175,222)	(175,222)	(169,570)	(174,476)	(169,570)	(175,222)	(1,456,362)
4470106	-	-	-	-	-	374	144	-	-	-	-	-	518
4470107	(2)	2	2	2	2	2	2	2	2	2	2	2	20
4470110	66	(87)	(657)	(1,059)	(511)	(38)	(0)	107	8	226	78	33	(1,834)
4470112	(2,659)	11	-	-	-	-	-	-	-	-	-	-	(2,648)
4470115	2,517	1,967	28,335	(24,220)	(1,210)	(1,499)	2,208	(26,889)	5,735	20,315	(47)	(233)	6,977
4470124	-	-	-	-	-	-	-	-	-	-	-	-	-
4470126	5,548	(41,547)	(24,358)	(57,073)	(269,278)	(29,523)	141,985	(129,765)	(103,065)	(30,298)	(18,850)	9,582	(546,643)
4470131	1,990	1,447	(2)	(0)	(2,910)	19	15	3	0	0	(0)	(0)	562
4470141	(2,732,644)	(2,870,409)	(21,258)	(58,394)	(140,175)	(46,333)	(299,810)	(711,595)	(108,242)	(6,993)	(2,352)	(27,551)	(7,025,757)
4470151	(1,252,323)	(1,215,289)	(1,033,296)	(841,081)	(898,656)	(38,829)	(49,541)	2,750	151	-	-	-	(5,326,116)
4470206	(931,206)	(28,784)	(12,384)	(17,874)	(41,363)	(69,544)	(105,758)	(189,515)	(34,805)	(7,977)	(29,132)	(9,978)	(1,478,321)
4470209	29,270	75,311	21,060	56,423	133,285	154,905	259,277	587,686	80,986	15,328	39,034	23,755	1,476,322
4470214	(149)	(164)	(118)	-	(151)	(74,058)	(363,992)	(90,980)	(7,646)	(36,758)	(8,486)	(6,921)	(589,423)
4470215	(1,224)	72	(102)	(29)	67	21,727	171,145	33,971	15,023	10,355	3,362	3,312	257,679
4470220	(59,966)	(53,965)	(86,009)	(217,179)	(129,210)	(214,321)	(44,034)	(126,755)	(147,701)	(134,659)	(24,369)	(83,313)	(1,321,481)
4470221	(64)	(2,500)	(779)	(2,063)	(3,324)	(5,087)	(1,493)	(4,886)	(6,294)	(4,415)	(1,430)	(679)	(33,014)
4470222	(277,904)	-	(37,969)	(34,553)	-	-	-	(2,480)	-	-	-	-	(352,905)
5550039	(234)	(201)	(72)	372	3,308	2,551	4,394	(3,750)	3,986	195	(963)	183	9,770
5550099	-	-	-	-	-	-	(113)	-	-	-	-	-	(113)
5570007	-	-	-	-	-	-	-	-	-	-	2,664	84,974	87,638
5614000	21,815	14,663	11,777	36,307	97,340	59,001	42,077	91,023	42,724	9,191	10,560	10,567	447,043
5614008	5,136	18,277	10,519	2,647	1,475	2,920	2,425	614	(67)	(144)	(228)	(386)	43,187
5615000	8,569	4,414	4,290	10,300	25,343	15,046	12,511	23,914	11,658	2,724	3,398	3,445	125,611
5757000	18,043	13,272	13,105	35,719	87,908	50,215	38,967	79,289	36,889	8,170	10,227	10,026	401,829
Total Off-System Sales	$ (2,118,401)	$ (3,008,880)	$ (115,827)	$ 352,431	$ 1,118,437	$ 56,630	$ (737,637)	$ (2,583,419)	$ (157,549)	$ (140,139)	$ (127,326)	$ (185,941)	$ (7,647,621)
75% of Total Off-System Sales	(1,588,801)	(2,256,660)	(86,870)	264,323	838,828	42,472	(553,228)	(1,937,564)	(118,162)	(105,104)	(95,495)	(139,456)	(5,735,716)
FMS Report	(1,588,801)	(2,256,660)	(86,870)	264,323	838,828	42,472	(553,228)	(1,937,564)	(118,162)	(105,104)	(95,495)	(139,456)	(5,735,716)
Difference	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Appalachian Power Company
Reconciliation of Off-Systems Sales Expense in FERC Account 447 to Amount Included in Fuel Factor Expense
For the Period January 1, 2015 through December 31, 2018

	Jan 2021	Feb 2021	Mar 2021	Apr 2021	May 2021	Jun 2021	Jul 2021	Aug 2021	Sep 2021	Oct 2021	Nov 2021	Dec 2021	Total 2021
4470001	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4470002	50,822	1,722,621	(723,200)	(107,392)	165,981	464,018	720,015	812,531	129,038	2,849,438	653,475	616,753	7,354,101
4470006	(1,314,751)	(1,217,160)	(1,105,083)	(831,141)	(857,437)	(577,722)	(716,025)	(728,682)	(543,615)	(555,872)	(714,067)	(220,672)	(9,382,225)
4470010	1,000,056	1,421,817	862,316	808,657	812,299	596,630	751,541	896,918	687,481	734,124	909,544	174,603	9,655,987
4470081	-	-	-	-	-	-	-	-	-	-	-	-	-
4470082	377,189	(194,273)	331,773	49,924	12,179	(9,577)	(138,706)	(178,811)	(212,432)	(170,334)	(95,349)	72,545	(155,872)
4470089	(359,664)	(8,603,049)	696,980	106,476	(1,289,170)	(4,261,586)	(5,516,933)	(5,940,286)	(238,825)	266,839	(183,787)	(3,817,590)	(29,140,594)
4470098	4,674	(273,581)	(156,471)	10,513	36,556	32,444	85,032	64,127	35,257	3,547	5,922	(20,203)	(173,184)
4470099	(175,222)	(158,265)	(175,222)	(169,570)	(175,222)	(455,570)	(470,798)	(470,777)	(455,590)	(455,590)	(470,776)	(440,403)	(4,073,006)
4470106	-	-	-	-	-	-	1,401	-	269	-	-	-	1,670
4470107	2	(0)	(0)	-	-	-	-	-	-	-	-	-	2
4470110	(60)	0	40	445	(28)	(82)	(76)	(55)	(93)	(48)	23	(10)	56
4470112	-	-	-	-	-	-	-	-	-	-	-	-	-
4470115	49,291	(37,551)	7,155	2,434	332	(1,673)	(13,212)	(344)	(8,511)	(5,066)	154	571	3,580
4470126	73,253	185,661	50,798	56,074	(47,929)	(172,032)	111,484	21,357	13,541	8,303	21,072	(274,569)	47,014
4470131	(0)	(13)	10	0	0	5	15	20	23	(16)	-	-	45
4470143	(1,444,621)	469,747	(6,207)	21	2,643	2,156	3,065,262	1,633,452	(1,475)	(2)	-	(378,148)	3,342,827
4470151	-	-	-	-	-	(1,090)	-	-	-	-	-	-	(1,090)
4470206	(59,008)	(280,481)	(46,503)	(9,993)	(69,151)	(204,546)	(300,335)	(242,185)	(55,997)	60	(617)	(111,025)	(1,379,782)
4470209	235,041	733,220	105,061	13,581	308,396	759,880	862,475	828,565	147,734	(920)	47	457,610	4,450,690
4470214	(928)	(2,164)	(1,695)	(13,137)	(21,036)	(106,747)	(207,749)	(252,182)	(105,102)	(50,887)	(17,312)	(5,116)	(784,055)
4470215	(3,267)	4,026	633	4,264	6,936	24,173	67,818	69,274	41,985	21,473	7,233	2,450	246,999
4470220	(131,918)	(100,669)	(53,958)	(27,844)	(174,620)	(71,803)	(90,819)	(66,336)	(121,294)	(452)	(274,790)	(73,372)	(1,187,876)
4470221	(13,603)	(2,608)	(6,286)	-	(11,928)	(2,317)	(632)	(676)	(400)	-	-	(9,324)	(47,774)
4470222	-	-	-	-	-	-	-	-	(80,296)	(1,417,639)	-	-	(1,497,935)
5350039	(44)	4,367	(138)	(251)	313	1,469	5,571	6,633	1,136	(91)	(466)	78	18,578
5550099	-	-	-	-	-	-	-	-	-	-	-	-	-
5570007	1,472	61	64	11,941	50	44,376	38	218,905	936	42	195	29	278,108
5614000	39,534	88,200	19,078	24,153	71,307	98,628	100,445	89,120	43,336	5,944	8,035	60,933	648,713
5614008	295	291	143	793	85	(1,339)	328	-	-	-	-	-	595
5616000	12,945	22,653	4,841	6,221	19,799	27,618	27,027	23,943	11,817	1,661	2,487	18,048	179,061
5757000	37,865	81,383	11,672	21,293	76,117	107,239	100,961	89,047	42,936	5,562	7,716	68,839	650,631
Total Off-System Sales	$ (1,620,648)	$ (6,125,767)	$ (184,199)	$ (42,538)	$ (1,133,528)	$ (3,707,449)	$ (1,555,871)	$ (3,126,441)	$ (668,138)	$ 1,239,076	$ (141,261)	$ (3,877,972)	$ (20,944,737)
75% of Total Off-System Sales	(1,215,486)	(4,594,326)	(138,149)	(31,903)	(850,146)	(2,780,586)	(1,166,903)	(2,344,831)	(501,104)	929,307	(105,946)	(2,908,479)	(15,708,553)
FMS Report	(1,215,486)	(4,594,326)	(138,149)	(31,903)	(850,146)	(2,780,586)	(1,166,903)	(2,344,831)	(501,104)	929,307	(105,946)	(2,908,479)	(15,708,553)
Difference	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Appalachian Power Company
Reconciliation of Off-Systems Sales Expense in FERC Account 447 to Amount Included in Fuel Factor Expense
For the Period January 1, 2015 through December 31, 2018

	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Total 2022
4470001	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4470002	(519,331)	(424,668)	(235,453)	295,024	214,978	537,058	3,648,219	3,261,523	(808,197)	417,172	(17,390)	581,343	6,950,277
4470006	(159,595)	(138,077)	(137,535)	(122,423)	(126,718)	1,698	485	(0)	-	-	-	-	(682,165)
4470010	117,350	175,794	205,695	249,982	215,667	(4,479)	(3,080)	(1,288)	(1,821)	(492)	389	489	954,205
4470082	(173,750)	(141,597)	(104,279)	(182,531)	(132,955)	(6,761)	-	(0)	-	-	-	-	(741,873)
4470089	724,248	312,467	244,650	(266,353)	(235,944)	(673,001)	(13,843,582)	(13,788,921)	639,702	180,731	24,196	(845,141)	(27,526,948)
4470098	(7,117)	(12,097)	3,068	6,867	17,263	10,823	(70,013)	1,611	28,257	(23,098)	(1,654)	(28,839)	(74,928)
4470099	(501,148)	(425,216)	(470,775)	(455,592)	(470,762)	(313,576)	(324,029)	(324,029)	(313,577)	(324,029)	(313,577)	(324,029)	(4,560,338)
4470106	-	586	-	-	282	639	281	-	142	340	-	539	2,808
4470107	-	-	-	-	-	-	-	-	-	-	-	-	-
4470110	17	(90)	(93)	(42)	151	(18)	(70)	40	29	24	44	(341)	(347)
4470112	-	-	-	-	-	-	-	-	-	-	-	-	-
4470115	8,357	2,104	4,647	(140,093)	2,462	3,838	3,368	14,329	28,942	(3,179)	(510)	4,823	(70,910)
4470126	241,644	45,550	79,947	78,953	113,760	97,910	458,612	316,968	45,588	5,796	75,880	143,901	1,704,509
4470131	-	-	-	-	-	-	-	-	-	-	-	-	-
4470143	352,324	23,003	(47)	-	-	-	-	-	-	-	-	-	375,281
4470151	-	-	-	-	-	-	-	-	-	2,047	-	-	2,047
4470206	(37,682)	(1,127)	22	(2,063)	(79)	(1,668)	(314,269)	(353,576)	(5,082)	(2,943)	(5,527)	(22,163)	(746,159)
4470209	71,795	12,469	(713)	1,321	367	5,677	1,135,120	1,090,971	15,504	7,397	13,952	64,500	2,418,360
4470214	(4,430)	(4,296)	(8,630)	(1,819)	(168,416)	(151,878)	(201,593)	(238,700)	(15,756)	-	-	-	(795,519)
4470215	1,642	1,811	2,698	1,801	13,714	87,299	67,692	72,011	8,597	(148)	(455)	(259)	256,402
4470220	(274,708)	(145,091)	(16,111)	(128,765)	(67,582)	(25,127)	(965,130)	(658,407)	(123,637)	(422,047)	(98,093)	(30,681)	(2,955,379)
4470221	(14,709)	(2,873)	(1,102)	-	(5,313)	(678)	(2,964)	(7,152)	(1,510)	-	(33,935)	(60,177)	(130,412)
4470222	-	-	-	-	(141,935)	-	-	-	-	-	-	(6,607)	(148,542)
5550039	147	(10)	(658)	(1,780)	(1,648)	(373)	2,442	(5,014)	(2,154)	(712)	(4,031)	2,938	(10,853)
5550099	-	-	-	-	-	-	-	-	-	-	-	-	-
5570007	1,188	-	-	-	-	-	-	173,618	-	-	-	-	174,806
5614000	12,768	36,945	22,483	23,364	32,083	24,229	55,833	49,377	13,496	9,164	33,569	25,603	
5614008	-	-	-	-	-	-	-	-	-	-	-	-	-
5618000	14,368	9,147	6,218	6,043	7,735	5,147	16,369	17,840	5,224	2,229	8,508	6,950	105,779
5757000	24,169	28,721	18,083	14,869	20,698	16,866	44,977	57,208	13,017	6,040	23,138	20,343	288,129
Total Off-System Sales	$ (122,453)	$ (646,547)	$ (387,884)	$ (623,237)	$ (712,191)	$ (386,377)	$ (10,291,332)	$ (10,321,591)	$ (473,235)	$ (145,707)	$ (295,496)	$ (466,807)	$ (25,211,771)
75% of Total Off-System Sales	(91,840)	(484,910)	(290,913)	(467,427)	(534,143)	(289,783)	(7,718,499)	(7,741,193)	(354,926)	(109,280)	(221,622)	(350,106)	(18,654,643)
FMS Report	(91,840)	(484,910)	(290,913)	(467,427)	(534,143)	(289,783)	(7,718,499)	(7,741,193)	(354,926)	(109,280)	(221,622)	(350,106)	(18,654,643)
Difference	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Statement VIII

Appalachian Power Company
Off-Systems Sales Expense by Month
For the Period January 1, 2019 through December 31, 2022

	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019	Jul 2019	Aug 2019	Sep 2019	Oct 2019	Nov 2019	Dec 2019	Total 2019
Total Off-System Sales Expense	$ (1,419,575)	$ (2,562,800)	$ 428,340	$ 1,105,930	$ (1,562,921)	$ (2,666,912)	$ (4,653,574)	$ (1,826,622)	$ (760,558)	$ 68,172	$ (356,796)	$ (3,443,530)	$(17,650,846)
75% of Total Off-System Sales Expense	(1,064,681)	(1,922,100)	321,255	829,448	(1,172,191)	(2,000,184)	(3,490,180)	(1,369,966)	(570,418)	51,129	(267,597)	(2,582,648)	(13,238,134)
25% Off-System Sales Margin	(354,894)	(640,700)	107,085	276,483	(390,730)	(666,728)	(1,163,393)	(456,655)	(190,139)	17,043	(89,199)	(860,883)	(4,412,711)
Virginia Jurisdictional Allocator	0.46918	0.46831	0.46380	0.46318	0.44506	0.47726	0.45216	0.45968	0.44840	0.44529	0.46042	0.47239	
Virginia Jurisdictional Off-System Sales Expense	$ (666,032)	$ (1,200,182)	$ 198,665	$ 512,244	$ (695,594)	$ (1,272,803)	$ (2,104,146)	$ (839,656)	$ (341,035)	$ 30,356	$ (164,276)	$ (1,626,686)	$ (8,169,144)
75% Virginia Jurisdictional Off-System Sales Expense	(499,524)	(900,137)	148,999	384,183	(521,695)	(954,602)	(1,578,109)	(629,742)	(255,776)	22,767	(123,207)	(1,220,014)	(6,126,858)
25% Virginia Jurisdictional Off-System Sales Margin	(166,508)	(300,046)	49,666	128,061	(173,898)	(318,201)	(526,036)	(209,914)	(85,259)	7,589	(41,069)	(406,671)	(2,042,286)

	Jan 2020	Feb 2020	Mar 2020	Apr 2020	May 2020	Jun 2020	Jul 2020	Aug 2020	Sep 2020	Oct 2020	Nov 2020	Dec 2020	Total 2020
Total Off-System Sales Expense	$ (2,118,401)	$ (3,008,880)	$ (115,827)	$ 352,431	$ 1,118,437	$ 56,630	$ (737,637)	$ (2,583,419)	$ (157,549)	$ (140,139)	$ (127,326)	$ (185,941)	$ (7,647,621)
75% of Total Off-System Sales Expense	(1,588,801)	(2,256,660)	(86,870)	264,323	838,828	42,472	(553,228)	(1,937,564)	(118,162)	(105,104)	(95,495)	(139,456)	(5,735,716)
25% Off-System Sales Margin	(529,600)	(752,220)	(28,957)	88,108	279,609	14,157	(184,409)	(645,855)	(39,387)	(35,035)	(31,832)	(46,485)	(1,911,905)
Virginia Jurisdictional Allocator	0.46134	0.46783	0.46049	0.45673	0.46983	0.47353	0.47580	0.45022	0.48138	0.46087	0.46875	0.49150	
Virginia Jurisdictional Off-System Sales Expense	$ (977,305)	$ (1,407,642)	$ (53,336)	$ 160,966	$ 525,471	$ 26,816	$ (350,969)	$ (1,163,096)	$ (75,841)	$ (64,586)	$ (59,684)	$ (91,389)	$ (3,530,597)
75% Virginia Jurisdictional Off-System Sales Expense	(732,979)	(1,055,731)	(40,002)	120,725	394,103	20,112	(263,227)	(872,322)	(56,881)	(48,440)	(44,763)	(68,542)	(2,647,948)
25% Virginia Jurisdictional Off-System Sales Margin	(244,326)	(351,910)	(13,334)	40,242	131,368	6,704	(87,742)	(290,774)	(18,960)	(16,147)	(14,921)	(22,847)	(882,649)

	Jan 2021	Feb 2021	Mar 2021	Apr 2021	May 2021	Jun 2021	Jul 2021	Aug 2021	Sep 2021	Oct 2021	Nov 2021	Dec 2021	Total 2021
Total Off-System Sales Expense	$ (1,620,648)	$ (6,125,767)	$ (184,199)	$ (42,538)	$ (1,133,528)	$ (3,707,449)	$ (1,555,871)	$ (3,126,441)	$ (668,138)	$ 1,239,076	$ (141,261)	$ (3,877,972)	$(20,944,737)
75% of Total Off-System Sales Expense	(1,215,486)	(4,594,326)	(138,149)	(31,903)	(850,146)	(2,780,586)	(1,166,903)	(2,344,831)	(501,104)	929,307	(105,946)	(2,908,479)	(15,708,553)
25% Off-System Sales Margin	(405,162)	(1,531,442)	(46,050)	(10,634)	(283,382)	(926,862)	(388,968)	(781,610)	(167,035)	309,769	(35,315)	(969,493)	(5,236,184)
Virginia Jurisdictional Allocator	0.47673	0.49014	0.46800	0.47952	0.46879	0.48675	0.46944	0.47737	0.47082	0.46639	0.47345	0.48020	
Virginia Jurisdictional Off-System Sales Expense	$ (772,617)	$ (3,002,496)	$ (86,204)	$ (20,398)	$ (531,390)	$ (1,804,601)	$ (730,387)	$ (1,492,472)	$ (314,573)	$ 577,890	$ (66,879)	$ (1,862,198)	$(10,106,325)
75% Virginia Jurisdictional Off-System Sales Expense	(579,462)	(2,251,872)	(64,653)	(15,298)	(398,542)	(1,353,450)	(547,790)	(1,119,354)	(235,930)	433,418	(50,160)	(1,396,649)	(7,579,743)
25% Virginia Jurisdictional Off-System Sales Margin	(193,154)	(750,624)	(21,551)	(5,099)	(132,847)	(451,150)	(182,597)	(373,118)	(78,643)	144,473	(16,720)	(465,550)	(2,526,581)

	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Total 2022
Total Off-System Sales Expense	$ (122,453)	$ (646,547)	$ (387,884)	$ (623,237)	$ (712,191)	$ (386,377)	$(10,291,332)	$(10,321,591)	$ (473,235)	$ (145,707)	$ (295,496)	$ (466,807)	$(24,872,857)
75% of Total Off-System Sales Expense	(91,840)	(484,910)	(290,913)	(467,427)	(534,143)	(289,783)	(7,718,499)	(7,741,193)	(354,926)	(109,280)	(221,622)	(350,106)	(18,654,643)
25% Off-System Sales Margin	(30,613)	(161,637)	(96,971)	(155,809)	(178,048)	(96,594)	(2,572,833)	(2,580,398)	(118,309)	(36,427)	(73,874)	(116,702)	(6,218,214)
Virginia Jurisdictional Allocator	0.478654	0.474162	0.466773	0.472034	0.478896	0.476171	0.477065	0.464715	0.462880	0.478043	0.471994	0.481273	
Virginia Jurisdictional Off-System Sales Expense	$ (58,613)	$ (306,568)	$ (181,054)	$ (294,189)	$ (341,066)	$ (183,981)	$ (4,909,634)	$ (4,796,598)	$ (219,051)	$ (69,654)	$ (139,472)	$ (224,662)	$(11,724,542)
75% Virginia Jurisdictional Off-System Sales Expense	(43,960)	(229,926)	(135,790)	(220,642)	(255,799)	(137,986)	(3,682,226)	(3,597,449)	(164,288)	(52,241)	(104,604)	(168,496)	(8,793,406)
25% Virginia Jurisdictional Off-System Sales Margin	(14,653)	(76,642)	(45,263)	(73,547)	(85,266)	(45,995)	(1,227,409)	(1,199,150)	(54,763)	(17,414)	(34,868)	(56,165)	(2,931,135)

Statement IX

Appalachian Power Company
Demurrage Expense by Month
For the Period January 1, 2019 through December 31, 2022

	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019	Jul 2019	Aug 2019	Sep 2019	Oct 2019	Nov 2019	Dec 2019	Total 2019
Amos	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mountaineer	21	5	-	-	-	-	-	-	-	-	-	-	26
Total	$ 21	$ 5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 26

	Jan 2020	Feb 2020	Mar 2020	Apr 2020	May 2020	Jun 2020	Jul 2020	Aug 2020	Sep 2020	Oct 2020	Nov 2020	Dec 2020	Total 2020
Amos	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mountaineer	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

	Jan 2021	Feb 2021	Mar 2021	Apr 2021	May 2021	Jun 2021	Jul 2021	Aug 2021	Sep 2021	Oct 2021	Nov 2021	Dec 2021	Total 2021
Amos	$ -	$ -	$ -	$ -	$ -	$ 28,252	$ 25,292	$ 17,569	$ 8,069	$ 1,028	$ 214	$ 2,858	$ 83,282
Mountaineer	-	-	-	-	-	4,780	12,783	12,209	4,604	-	-	7,680	42,057
Total	$ -	$ -	$ -	$ -	$ -	$ 33,032	$ 38,075	$ 29,778	$ 12,673	$ 1,028	$ 214	$ 10,538	$ 125,339

	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Total 2022
Amos	$ 1,967	$ 572	$ 112	$ 606	$ 856	$ 1,026	$ 14,288	$ 12,956	$ 5,660	$ (8)	$ 1,942	$ 6,424	$ 46,404
Mountaineer	9,905	4,538	1,324	-	-	909	5,412	7,251	2,763	11,648	11,528	9,730	65,008
Total	$ 11,872	$ 5,110	$ 1,437	$ 606	$ 856	$ 1,935	$ 19,700	$ 20,207	$ 8,424	$ 11,640	$ 13,470	$ 16,154	$ 111,411

2312601797

Statement X

Appalachian Power Company
Generation Plant Net Capacity Information (MWs)
As of December 31, 2022

Plant	Fuel Type	Units	Dec 2018	Dec 2019	Dec 2020	Dec 2021	Dec 2022
Amos	Coal	3	2,930	2,930	2,930	2,930	2,930
Mountaineer	Coal	1	1,320	1,320	1,320	1,320	1,320
Total Coal		4	4,250	4,250	4,250	4,250	4,250
Ceredo	Natural Gas	6	516	516	516	516	516
Dresden	Natural Gas	3	665	665	665	665	665
Clinch River	Natural Gas	2	465	465	465	465	465
Total Natural Gas		11	1,646	1,646	1,646	1,646	1,646
Smith Mountain	Hydro		588	585	585	585	585
Consolidated Hydro	Hydro		202	202	201	200	200
Total Hydro			790	787	786	785	785
Total All Plants		15	6,686	6,683	6,682	6,681	6,681

APPENDIX

231260197

Statement of Recoveries

Appalachian Power Company
Virginia Jurisdictional Fuel Factor Revenue by Month
For the Period January 1, 2019 through December 31, 2022

	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019	Jul 2019	Aug 2019	Sep 2019	Oct 2019	Nov 2019	Dec 2019	Total 2019
In-Period Factor	$ 0.02192	$ 0.02122	$ 0.02122	$ 0.02122	$ 0.02123	$ 0.02122	$ 0.02122	$ 0.02122	$ 0.02122	$ 0.02122	$ 0.02039	$ 0.02039	
Correction Factor	$ 0.00425	$ 0.00425	$ 0.00425	$ 0.00425	$ 0.00425	$ 0.00425	$ 0.00425	$ 0.00425	$ 0.00425	$ 0.00425	$ 0.00261	$ 0.00261	
Total Fuel Factor	$ 0.02547	$ 0.02547	$ 0.02547	$ 0.02547	$ 0.02547	$ 0.02547	$ 0.02547	$ 0.02547	$ 0.02547	$ 0.02547	$ 0.02300	$ 0.02300	
Va. Juris Sales (kWh)	1,450,829,301	1,181,818,153	1,278,465,634	978,817,479	1,027,417,530	1,089,610,765	1,260,623,035	1,197,687,546	1,085,323,083	998,465,753	1,210,563,762	1,311,859,923	14,071,481,964
In-Period Revenue	$ 80,786,598	$ 25,078,181	$ 27,129,041	$ 20,770,507	$ 21,801,800	$ 23,121,540	$ 26,750,421	$ 25,414,930	$ 23,030,556	$ 21,187,443	$ 24,683,395	$ 26,748,824	$ 296,503,236
Correction Factor Revenue	$ 6,166,025	$ 5,022,727	$ 5,433,479	$ 4,159,974	$ 4,366,525	$ 4,630,846	$ 5,357,648	$ 5,090,172	$ 4,612,623	$ 4,243,479	$ 3,159,571	$ 3,423,954	$ 55,667,024
Total Fuel Factor Revenue	$ 36,952,622	$ 30,100,908	$ 32,562,520	$ 24,930,481	$ 26,168,324	$ 27,752,386	$ 32,108,069	$ 30,505,102	$ 27,643,179	$ 25,430,923	$ 27,842,967	$ 30,172,778	$ 352,170,259

	Jan 2020	Feb 2020	Mar 2020	Apr 2020	May 2020	Jun 2020	Jul 2020	Aug 2020	Sep 2020	Oct 2020	Nov 2020	Dec 2020	Total 2020
In-Period Factor	$ 0.02039	$ 0.02039	$ 0.02039	$ 0.02039	$ 0.02039	$ 0.03039	$ 0.02039	$ 0.02039	$ 0.02039	$ 0.02039	$ 0.02020	$ 0.02020	
Correction Factor	$ 0.00261	$ 0.00261	$ 0.00261	$ 0.00261	$ 0.00261	$ 0.00261	$ 0.00261	$ 0.00261	$ 0.00261	$ 0.00261	$ (0.00021)	$ (0.00021)	
Total Fuel Factor	$ 0.02300	$ 0.02300	$ 0.02300	$ 0.02300	$ 0.02300	$ 0.02300	$ 0.02300	$ 0.02300	$ 0.02300	$ 0.02300	$ 0.01999	$ 0.01999	
Va. Juris Sales (kWh)	1,327,648,062	1,250,924,465	1,184,112,414	979,220,450	940,213,903	1,012,087,556	1,147,730,706	1,205,263,163	1,119,478,083	974,922,444	966,881,582	1,252,478,969	13,360,961,797
In-Period Revenue	$ 27,070,744	$ 25,506,350	$ 24,144,052	$ 19,966,305	$ 19,170,961	$ 20,636,465	$ 23,402,229	$ 24,575,316	$ 22,826,158	$ 19,878,669	$ 19,531,008	$ 25,300,075	$ 272,008,333
Correction Factor Revenue	$ 3,465,161	$ 3,264,913	$ 3,090,533	$ 2,555,765	$ 2,453,958	$ 2,641,549	$ 2,995,577	$ 3,145,737	$ 2,921,838	$ 2,544,548	$ (203,045)	$ (263,021)	$ 28,613,514
Total Fuel Factor Revenue	$ 30,535,905	$ 28,771,263	$ 27,234,586	$ 22,522,070	$ 21,624,920	$ 23,278,014	$ 26,397,806	$ 27,721,053	$ 25,747,996	$ 22,423,216	$ 19,327,963	$ 25,037,055	$ 300,621,846

	Jan 2021	Feb 2021	Mar 2021	Apr 2021	May 2021	Jun 2021	Jul 2021	Aug 2021	Sep 2021	Oct 2021	Nov 2021	Dec 2021	Total 2021
In-Period Factor	$ 0.02020	$ 0.02020	$ 0.02020	$ 0.02020	$ 0.02020	$ 0.02020	$ 0.02020	$ 0.02020	$ 0.02020	$ 0.02020	$ 0.02021	$ 0.02021	
Correction Factor	$ (0.00021)	$ (0.00021)	$ (0.00021)	$ (0.00021)	$ (0.00021)	$ (0.00021)	$ (0.00021)	$ (0.00021)	$ (0.00021)	$ (0.00021)	$ 0.00279	$ 0.00279	
Total Fuel Factor	$ 0.01999	$ 0.01999	$ 0.01999	$ 0.01999	$ 0.01999	$ 0.01999	$ 0.01999	$ 0.01999	$ 0.01999	$ 0.01999	$ 0.02300	$ 0.02300	
Va. Juris Sales (kWh)	1,409,225,242	1,316,730,281	1,106,031,037	1,007,748,034	1,028,610,035	1,102,836,625	1,174,642,666	1,252,622,389	1,008,080,618	1,032,879,267	1,178,342,824	1,190,989,359	13,808,737,877
In-Period Revenue	$ 28,466,350	$ 26,597,952	$ 22,341,827	$ 20,356,510	$ 20,777,923	$ 22,277,300	$ 23,727,782	$ 25,302,972	$ 20,363,228	$ 20,864,161	$ 23,814,298	$ 24,069,895	$ 278,960,198
Correction Factor Revenue	$ (295,937)	$ (276,513)	$ (232,267)	$ (211,627)	$ (216,008)	$ (231,596)	$ (246,675)	$ (263,051)	$ (211,697)	$ (216,905)	$ 3,287,575	$ 3,322,860	$ 4,208,160
Total Fuel Factor Revenue	$ 28,170,413	$ 26,321,438	$ 22,109,560	$ 20,144,883	$ 20,561,915	$ 22,045,704	$ 23,481,107	$ 25,039,922	$ 20,151,532	$ 20,647,257	$ 27,101,873	$ 27,392,755	$ 283,168,359

	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Total 2022
In-Period Factor	$ 0.02021	$ 0.02021	$ 0.02021	$ 0.02021	$ 0.02021	$ 0.02021	$ 0.02021	$ 0.02021	$ 0.02031	$ 0.02021	$ 0.03011	$ 0.03011	
Correction Factor	$ 0.00279	$ 0.00279	$ 0.00279	$ 0.00279	$ 0.00279	$ 0.00279	$ 0.00279	$ 0.00279	$ 0.00279	$ 0.00279	$ 0.01308	$ 0.01308	
Total Fuel Factor	$ 0.02300	$ 0.02300	$ 0.02300	$ 0.02300	$ 0.02300	$ 0.02300	$ 0.02300	$ 0.02300	$ 0.02300	$ 0.02300	$ 0.04319	$ 0.04319	
Va. Juris Sales (kWh)	1,498,549,101	1,238,594,884	1,114,389,435	989,423,379	1,080,388,214	1,098,177,279	1,189,156,554	1,195,166,158	986,733,279	1,058,366,329	1,104,196,316	1,373,082,974	13,926,223,902
Total Fuel Factor Revenue	34,465,501	28,487,312	25,512,923	22,756,987	24,858,971	25,270,667	27,415,432	27,488,950	22,695,686	33,592,285	37,855,696	38,826,833	369,227,242

Notes: [A 2022 recoveries are recorded using actual billed and accrued revenue from the Company's billing system. See the Supplemental Response to Staff DR 1-6 and Staff DR 9-74.

Statement of Expenses

Appalachian Power Company
Virginia Jurisdictional Fuel Expense by Month
For the Period January 1, 2019 through December 31, 2022

	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019	Jul 2019	Aug 2019	Sep 2019	Oct 2019	Nov 2019	Dec 2019	Total 2019
Coal	$ 23,532,485	$ 14,442,951	$ 11,443,894	$ 10,157,834	$ 16,362,889	$ 15,915,343	$ 20,210,299	$ 16,381,661	$ 9,701,705	$ 4,472,190	$ 7,772,738	$ 8,903,882	$ 159,297,872
Oil	140,029	191,527	331,394	373,687	367,372	300,953	577,768	494,185	325,033	431,192	561,239	544,514	4,638,893
Natural Gas	5,065,500	3,945,200	4,613,022	3,325,331	2,638,907	3,454,443	5,909,224	3,551,662	3,213,457	3,581,261	4,259,261	2,956,029	46,513,297
Purchased Power	4,668,944	9,311,753	14,656,978	8,624,933	2,970,188	1,404,322	(515,769)	5,697,800	11,793,565	13,896,499	16,764,097	15,575,450	104,848,760
Off-System Sales	(666,032)	(1,200,182)	198,665	512,244	(695,594)	(1,272,803)	(2,104,146)	(839,656)	(341,035)	30,356	(164,276)	(1,626,686)	(8,169,144)
25% OSS Margin	166,508	300,046	(49,666)	(128,061)	173,898	318,201	526,036	209,914	85,259	(7,589)	41,069	406,671	2,042,286
Total Juris. Fuel Expense	$ 32,907,434	$ 26,991,294	$ 31,194,286	$ 22,865,968	$ 21,817,661	$ 20,120,460	$ 24,603,412	$ 25,495,567	$ 24,777,985	$ 22,403,909	$ 29,234,127	$ 26,759,862	$ 309,171,964

	Jan 2020	Feb 2020	Mar 2020	Apr 2020	May 2020	Jun 2020	Jul 2020	Aug 2020	Sep 2020	Oct 2020	Nov 2020	Dec 2020	Total 2020
Coal	$ 6,101,280	$ 11,195,886	$ 12,188,906	$ 13,280,959	$ 17,872,211	$ 12,755,427	$ 17,407,685	$ 19,926,951	$ 14,514,943	$ 8,672,257	$ 6,117,608	$ 11,650,686	$ 151,684,799
Oil	911,051	1,076,528	188,277	236,522	149,666	121,985	593,878	440,121	363,417	70,172	439,621	359,496	4,950,733
Natural Gas	2,657,517	2,507,082	2,298,440	1,536,950	2,204,648	2,730,422	3,870,843	2,567,880	2,155,097	1,747,549	2,068,391	3,622,942	29,967,761
Purchased Power	19,053,504	10,939,008	6,873,540	3,007,945	(1,648,782)	3,592,448	4,939,252	439,476	4,255,307	9,736,458	12,210,030	15,863,750	89,261,937
Off-System Sales	(977,305)	(1,407,642)	(53,336)	160,966	525,471	26,816	(350,969)	(1,163,096)	(75,841)	(64,586)	(59,684)	(91,389)	(3,530,597)
25% OSS Margin	244,326	351,910	13,334	(40,242)	(131,368)	(6,704)	87,742	290,774	18,960	16,147	14,921	22,847	882,649
Total Juris. Fuel Expense	$ 27,990,374	$ 24,662,772	$ 21,509,159	$ 18,183,100	$ 18,971,845	$ 19,220,395	$ 26,548,431	$ 22,502,106	$ 21,231,884	$ 20,177,997	$ 20,790,887	$ 31,428,331	$ 273,217,282

	Jan 2021	Feb 2021	Mar 2021	Apr 2021	May 2021	Jun 2021	Jul 2021	Aug 2021	Sep 2021	Oct 2021	Nov 2021	Dec 2021	Total 2021
Coal	$ 20,830,265	$ 23,388,713	$ 10,104,477	$ 8,196,140	$ 17,227,909	$ 23,169,797	$ 23,519,033	$ 22,968,894	$ 15,594,705	$ 3,533,966	$ 775,781	$ 19,273,697	$ 188,583,377
Oil	373,981	155,597	101,792	681,031	457,051	639,548	107,316	524,216	177,523	87,845	325,864	1,400,052	5,031,816
Natural Gas	3,643,506	6,800,716	3,317,006	2,422,770	3,916,679	4,587,306	4,949,103	6,672,313	2,287,924	3,012,225	10,015,013	6,307,872	57,932,435
Purchased Power	5,566,469	395,552	10,388,656	12,597,517	1,131,688	(2,639,549)	(1,007,124)	(897,044)	13,800,324	44,048,615	53,373,364	9,882,302	146,640,769
Off System Sales	(772,617)	(3,002,496)	(86,204)	(20,398)	(531,390)	(1,804,601)	(730,387)	(1,492,472)	(314,573)	577,890	(66,879)	(1,862,198)	(10,106,325)
25% OSS Margin	193,154	750,624	21,551	5,099	132,847	451,150	182,597	373,118	78,643	(144,473)	16,720	465,550	2,526,581
Total Juris. Fuel Expense	$ 29,834,758	$ 28,488,705	$ 23,847,278	$ 23,882,160	$ 22,334,786	$ 24,403,652	$ 27,020,538	$ 28,149,025	$ 31,624,546	$ 51,116,068	$ 64,439,863	$ 35,467,274	$ 390,608,652

	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022	Jul 2022	Aug 2022	Sep 2022	Oct 2022	Nov 2022	Dec 2022	Total 2022
Coal	$ 20,973,015	$ 13,497,868	$ 5,746,648	$ 3,823,890	$ 6,203,133	$ 9,061,956	$ 24,725,140	$ 25,907,117	$ 10,267,988	$ 6,829,801	$ 10,279,338	$ 21,987,453	$ 159,303,345
Oil	229,319	328,832	72,523	366,460	742,074	1,192,544	873,259	429,650	814,587	107,573	1,811,099	741,417	7,709,337
Natural Gas	5,910,904	7,064,807	5,887,032	7,052,074	9,087,734	13,378,247	13,600,644	12,303,089	9,061,444	7,025,355	7,518,854	14,544,898	112,435,081
Purchased Power	22,497,702	24,762,628	34,105,890	41,826,153	49,435,510	47,417,246	10,134,368	6,068,655	38,255,631	33,027,278	28,136,878	45,413,716	381,081,653
Off-System Sales	(58,613)	(306,568)	(181,054)	(294,189)	(341,066)	(183,981)	(4,909,634)	(4,796,598)	(219,051)	(69,654)	(139,472)	(224,662)	(11,724,542)
25% OSS Margin	14,653	76,642	45,263	73,547	85,266	45,995	1,227,409	1,199,150	54,763	17,414	34,868	56,165	2,931,135
Total Juris. Fuel Expense	$ 49,566,980	$ 45,424,208	$ 45,676,302	$ 52,849,935	$ 65,212,651	$ 70,912,005	$ 45,651,185	$ 41,111,062	$ 58,235,362	$ 46,937,767	$ 47,641,564	$ 82,518,988	$ 651,738,010

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. APCo VA Fuel Factor Audit (2019 through 2022) and 2023 Fuel Factor Filing
(PUR-2023-00156)
Interrogatories and Requests for the Production
of Documents by the STAFF OF THE STATE CORPORATION COMMISSION
Staff Audit Set 1
To Appalachian Power Company

Interrogatory Staff 1-6:

Please provide a narrative to explain any changes to the Company's fuel accounting policies or processes which occurred during the Audit Period. Include a description of and justification for the change(s) with any relevant supporting documentation.

Response Staff 1-6:

Please see Staff 1-6 Attachment 1 for a copy of AEP's Accounting Bulletin #4 - Accounting for Coal Costs. There were no changes to this bulletin during the Audit Period.

Supplemental Response Staff 1-6:

In January 2022, the Company changed the methodology for the VA fuel revenues included in the over/under fuel deferral calculation. Instead of taking monthly KWH's (billed and net accrued) and multiplying by the fuel rate in effect for that month, the Company began using revenues produced from our billing system, MACSS, which is more correlated with the fuel dollars that show up on customer bills.

The foregoing response is made by Brian J. Frantz, Dir Accounting, on behalf of Appalachian Power Company.

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. APCo VA Fuel Factor Audit (2019 through 2022)
Interrogatories and Requests for the Production
of Documents by the STAFF OF THE STATE CORPORATION COMMISSION
Staff Set 2
To Appalachian Power Company

Interrogatory Staff 2-19:

Please provide all supporting documentation for any adjustments to coal inventories during the Audit Period, listed above. Include any and all documents to confirm the cost and quantity of coal inventory adjustments and coal pile surveys reported in the FMS Reports.

Response Staff 2-19:

Please see Staff 2-19 Attachment 1 for general ledger activity in FERC account 151 for any survey adjustments to coal inventories during the audit period as reported in the FMS reports. Please note that Amos Plant had 2 separate coal piles during the entire audit period and Mountaineer Plant started a second pile in September 2022, so Staff 2-19 Attachment 1 has a reconciliation by coal pile, as the Company computes separate adjustments by coal pile, which agrees to the total adjustment reflected on the FMS reports. Please see Staff 2-19 Attachment 2 for the support behind these coal pile adjustments.

The foregoing response is made by Brian J. Frantz, Dir Accounting, on behalf of Appalachian Power Company.

23126015

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. APCo VA Fuel Factor Audit (2019 through 2022) and 2023 Fuel Factor Filing
Interrogatories and Requests for the Production
of Documents by the STAFF OF THE STATE CORPORATION COMMISSION
Staff Set 3
To Appalachian Power Company

Interrogatory Staff 3-45:

Please refer to the response to Staff Data Request 2-21. Please provide a narrative to explain the timing and impact of the correction to fuel expense for the miscategorized costs identified in Staff Data Request 2-21. Please include a copy of the journal entry.

Response Staff 3-45:

The $4,700 of miscategorized costs identified in Staff Data Request 2-21 will be credited to FERC account 151 and debited to FERC account 154 in 2023 and will adjust the weighted average cost of the inventory recorded in those accounts. Please see Staff 3-45 Attachment 1 for copy of the journal entry.

The foregoing response is made by Brian J. Frantz, Dir Accounting, on behalf of Appalachian Power Company.

231260197

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. APCo VA Fuel Factor Audit (2019 through 2022) and 2023 Fuel Factor Filing
Interrogatories and Requests for the Production
of Documents by the STAFF OF THE STATE CORPORATION COMMISSION
Staff Set 4
To Appalachian Power Company

Interrogatory Staff 4-52.:

"Staff 2-19 Attachment 1" provides a total of 14 coal pile survey adjustments. The monthly FMS reports only reflect coal pile survey adjustments on FM-1 in April of 2019. Please provide an explanation as to why coal pile survey adjustments as reflected on DR 2-19 would not be reflected in the FMS reports.

Response Staff 4-52.:

The coal pile survey adjustments for the other months during 2019-2022, as reflected on DR 2-19, were not properly captured in the monthly FMS reports filed by the Company.

The foregoing response is made by William K. Castle, Dir Regulatory Svcs, and Brian J. Frantz, Dir Accounting, on behalf of Appalachian Power Company.

231260197

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. APCo VA Fuel Factor Audit (2019 through 2022) and 2023 Fuel Factor Filing
Interrogatories and Requests for the Production
of Documents by the STAFF OF THE STATE CORPORATION COMMISSION
Staff Audit Set 5
To Appalachian Power Company

Interrogatory Staff 5-58:

Please see the Company's 2021 Fuel Factor filing, Case No. PUR-2021-00205. Company witness Keeton's Schedule 2 includes an adjustment for "March 2019-May 2021 VA Deferred Fuel for Demurrage Charges" reflecting an over-recovery of $306,203. Please provide a narrative explanation for this adjustment as well as supporting calculations.

Response Staff 5-58:

In July 2021, the Company noted that the deferred fuel calculation was not excluding demurrage costs from March 2019 through May 2021. The Company revised the calculations for that period and recorded an adjustment in July 2021 business. The original calculations showed higher costs, therefore, this adjustment reflected an over-recovery of $306,203. Please refer to Staff 5-58 Attachment 1 for summary, by month, of adjustment.

The foregoing response is made by Brian J. Frantz, Dir Accounting, on behalf of Appalachian Power Company.

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
SCC CASE NO. APCo VA Fuel Factor Audit (2019 through 2022) and 2023 Fuel Factor Filing
Interrogatories and Requests for the Production
of Documents by the STAFF OF THE STATE CORPORATION COMMISSION
Staff Audit Set 5
To Appalachian Power Company

Interrogatory Staff 5-61:

As noted in 5-60 above, account 5010040 – Gas Procurement Sales Net is included in the fuel factor calculations. However, it only begins to be included in December of 2020. The trial balance shows amounts in this account in May through October of 2020, but these are not included in the fuel factor. Why was this account not included before December 2020?

Response Staff 5-61:

The Company inadvertently excluded the activity in account 5010040 for the months of May 2020-November 2020 in the fuel factor calculations. The total Company activity in this account for that period was a credit of $57,654. The Company will revise the monthly fuel factor calculations for these months, to include this account in the calculation, and book an entry to correct the general ledger in 2023 business.

The foregoing response is made by Brian J. Frantz, Dir Accounting, on behalf of Appalachian Power Company.

COMMONWEALTH OF VIRGINIA
STATE CORPORATION COMMISSION
APPLICATION OF
APPALACHIAN POWER COMPANY
APCo VA Fuel Factor Audit (2019 through 2022)
Interrogatories and Requests for the Production
of Documents by the STAFF OF THE STATE CORPORATION COMMISSION
Staff Audit Set 9
To Appalachian Power Company

Interrogatory Staff 9-74:

Please refer to the supplemental response to Staff Data Request 1-6.
a): Has the Company's change in methodology for recognizing VA fuel revenues been included in the FMS report? If so, when was the change made and what adjustments were required to restate revenues and/or the over/under deferred fuel balance? Please provide a copy of the applicable FMS report and include detail to support any adjustments to VA fuel revenues and the over/under deferred fuel recovery balance.

b): Does the Company intend on revising any FMS reports during the Audit period? If not, please provide a schedule that reconciles the monthly in-period revenues, monthly correction factor revenues, and monthly over/under deferred fuel recovery balances in the 2022 FMS reports to the monthly actual fuel factor recoveries and monthly cumulative fuel cost over(under) recovery positions from the 2 most recent fuel factor cases (Schedule 2, Witness: WKC, PUR-2022-00139 and Schedule 2, Witness: JAS, PUR-2023-00156).

c): Has the Company modified the FMS report for changes in methodology for recognizing VA fuel revenues in calculating the over/under deferred fuel recovery balance? If so, please provide a narrative to explain these modifications.

Response Staff 9-74:

a): No.
b): Yes. The Company will work with the Staff to determine a mutually acceptable timeline for completing these revisions.
c): The Company has not yet modified the FMS reports to reflect the changes in methodology. See also the Company's response to Part b.

The foregoing response is made by Brian J. Frantz, Dir Accounting, and John A. Stevens, Regulatory Consultant Staff, on behalf of Appalachian Power Company.

Kentucky Power Company
KPSC Case No. 2023-00008
Commission Staff's Initial Post-Hearing Data Requests
Dated February 29, 2024

DATA REQUEST

KPSC PHDR_12	Provide documentation relating to maintenance personnel work schedules and planning as it relates to responding to maintenance requests on Sundays and holidays.

RESPONSE

The Company makes a determination about whether to prioritize the timing or the cost of conducting repairs and maintenance work during outages based on the specific circumstances. There are situations in which incurring the additional costs associated with work during Sundays and holidays is justified, but in other situations it is preferable, and to the benefit of customers, to not incur those additional costs even if it results in a longer outage time. The Company makes these decisions based on the specific circumstances at the time. Please see KPCO_R_KPSC_PHDR_12_Attachment1 and KPCO_R_KPSC_PHDR_12_Attachment2 for the requested information for Big Sandy Plant and Mitchell Plant respectively.

Witness: Douglas J. Rosenberger

Witness: David L. Mell

DATA REQUEST

KPSC PHDR_13	Provide all unit outage reports from November 1, 2020, through October 31,2022.

RESPONSE

Under current operating characteristics, it is not cost-effective to prepare comprehensive outage reports. Instead, the Company maintains limited documentation specific to the particular operating teams, only on an as-practical basis, and appropriate for the circumstances or particular type of work.

Witness: Douglas J. Rosenberger

Witness: David L. Mell

Kentucky Power Company
KPSC Case No. 2023-00008
Commission Staff's Initial Post-Hearing Data Requests
Dated February 29, 2024

DATA REQUEST

KPSC PHDR_14	Identify all Kentucky Power unit outages since February 1, 2022, by date and outage type.

RESPONSE

The Company respectfully objects to this request on the basis that it is not reasonably calculated to lead to the discovery of admissible evidence, and it is overbroad as it pertains to a time period outside of the review period in the present case. Subject to and without waiving these objections, please see KPCO_R_KPSC_PHDR_14_Attachment1 for the requested information.

Witness: Douglas J. Rosenberger

Witness: David L. Mell

VERIFICATION

The undersigned, Alex E. Vaughan, being duly sworn, deposes and says he is the Managing Director for Renewables and Fuel Strategy for American Electric Power Service Corporation that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Alex E. Vaughan

______________________)
) Case No. 2023-00008
______________________)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Alex E. Vaughan, on 3/20/2024.

Notary Public

My Commission Expires Never

Notary ID Number NoID

NOTARIAL SEAL STATE OF OHIO

Paul D. Flory
Attorney At Law
Notary Public, State of Ohio
My commission has no expiration date
Sec. 147.03 R.C.

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E-Signature Summary

E-Signature 1: Kimberly Chilcote (KKC)
March 21, 2024 06:15:58 -8:00 [C30E48DC4461] [167.239.221.101]
kkchilcote@aep.com (Principal) (Personally Known)

E-Signature Notary: Marilyn Michelle Caldwell (MMC)
March 21, 2024 06:15:58 -8:00 [56B175C5D4A3] [167.239.221.107]
mmcaldwell@aep.com
I, Marilyn Michelle Caldwell, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Kimberly K. Chilcote, being duly sworn, deposes and says she is a Coal Procurement Manager for American Electric Power Service Corporation, that she has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of her information, knowledge, and belief.

Kimberly Chilcote

Kimberly K. Chilcote

Commonwealth of Kentucky)
) Case No. 2023-00008
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Kimberly K. Chilcote, on March 21, 2024.

Marilyn M Caldwell

Notary Public

MARILYN MICHELLE CALDWELL
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission# KYNP71841
My Commission Expires May 05, 2027

My Commission Expires May 5, 2027 Notarial act performed by audio-visual communication

Notary ID Number KYNP71841

VERIFICATION

The undersigned, Mark D. O'Brien, being duly sworn, deposes and says he is the Director of Generation and Market Simulation for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Mark D. O'Brien

State of Ohio)
) Case No. 2023-00008
County of Frankin

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Mark D. O'Brien, on March 21st, 2024.

Notary Public

NATARIA L. SCALES
NOTARY PUBLIC • STATE OF OHIO
MY COMMISSION NO. 2017-RE-637054
MY COMMISSION EXPIRES MARCH 7, 2027

My Commission Expires 03-07-2027

Notary ID Number 2017-RE-637054

Rosenberger Discovery Verification Form.doc

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E-Signature Summary

E-Signature 1: Douglas Rosenberger (DJR)
March 18, 2024 10:32:48 -8:00 [C37DB5292A14] [167.239.221.107]
djrosenberger@aep.com (Principal) (Personally Known)

E-Signature Notary: Marilyn Michelle Caldwell (MMC)
March 18, 2024 10:32:48 -8:00 [5DAD07E2FAEE] [167.239.221.107]
mmcaldwell@aep.com
I, Marilyn Michelle Caldwell, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Douglas J. Rosenberger, being duly sworn, deposes and says he is the Director Regional Engineering Services for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief..

Douglas Rosenberger

Douglas J. Rosenberger

Commonwealth of Kentucky)
) Case No. 2023-00008
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Douglas J. Rosenberger, on March 14, 2024.

Notary Pu[blic]

MARILYN MICHELLE CALDWELL
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission # KYNP71841
My Commission Expires May 05, 2027

Notarial act performed by audio-visual communication

My Commission Expires May 5, 2027

Notary ID Number KYNP71841

Mell Discovery Verification Form.doc

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E-Signature Summary

E-Signature 1: David L Mell (DLM)
March 20, 2024 11:29:13 -8:00 [59FE88CD88B4] [167.239.221.106]
dlmell@aep.com (Principal) (Personally Known)

E-Signature Notary: Marilyn Michelle Caldwell (MMC)
March 20, 2024 11:29:13 -8:00 [124EFF5F2E9C] [167.239.221.107]
mmcaldwell@aep.com
I, Marilyn Michelle Caldwell, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, David L. Mell, being duly sworn, deposes and says he is the Energy Production Superintendent – Big Sandy Plant for Kentucky Power Company, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

David L Mell

David L. Mell

Commonwealth of Kentucky)

) Case No. 2023-00008

County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by David L. Mell, on March 20, 2024.

Notary Public

MARILYN MICHELLE CALDWELL
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission # KYNP71841
My Commission Expires May 05, 2027

My Commission Expires May5, 2027

Notarial act performed by audio-visual communication

Notary ID Number KYNP71841