DATA REQUEST

AG 1-01 According to the articles at the link below, several major insurance companies have issued new directives stating they will cease: (i) issuing new insurance policies to companies that derive more than 30% of their revenues from thermal coal mining; and (ii) making new investments in companies that have a large exposure to thermal coal mining or coal-based energy production. According to the second article ("Energy Transition Prompts More Insurers to Back Away From Coal"), insurance policy premiums and the cost of capital will increase for utilities having significant coal-fired generation resources.

a. Provide a discussion of whether these new directives on behalf of major insurance companies will have any effect on the Company, its production facilities, and fuel sources, and if so, how.

b. State whether these new directives have entered into the Company's planning and decision making regarding the instant IRP. If not, state whether they will or may enter into the Company's planning and decision making regarding future IRP filings.

https://www.latimes.com/business/la-fi-chubb-bans-coal-coverage-20190701-story.html ;
https://www.axios.com/energy-transition-prompts-more-insurers-back-away-from-coal-1e85a50f-ef35-4ce7-b57b-0bec745a376e.html

RESPONSE

a. The Company has no knowledge of how the referenced articles were prepared, or the accuracy of the information contained within. To the extent that a significant portion of the Company's insurance providers prohibit extending coverage based on various coal exposure criteria, there may be an adverse impact to the cost or availability of insurance. To date, the majority of the Company's insurance providers have recognized the Company's efforts to diversify its generation fleet and the Company continues to have access to adequate insurance capacity. The Company regularly monitors risk associated with its major suppliers, including fuel suppliers. If the Company's fuel suppliers were required to pay more for insurance, it is expected those costs would be reflected in future coal prices.

b. These specific issues were not explicitly addressed in this IRP. As stated in the Company's response to part a., the Company evaluates risk associated with its major suppliers, including coal suppliers. The impacts associated with fuel supplier risk are generally included in the forecasted cost of fuel.

Witness: Brian K. West

Witness: John F. Torpey

DATA REQUEST

AG 1-02 Explain whether the Company's IRP modelling takes into consideration the escalating number of coal mining company bankruptcy filings. If not, why not?

a. If the modeling does not take this factor into consideration, explain what would have to be done to do so.

b. If the Company believes the increasing incidence of coal mining company bankruptcies is of little or no concern, explain fully why not.

c. Provide the most current forecast of KPCo's retail power sales to the mining industry.

d. Provide any coal price estimates for the next ten (10) years that may have conducted.

e. Is KPCo aware of any Moody's Investors Service analyses regarding the stability of coal mining companies over the next one (1) to five (5) years? If so, provide copies.

RESPONSE

The Company notes that coal companies may continue to operate during and after bankruptcy proceedings. The Company is concerned about the financial health of all its customers, including coal suppliers. The IRP reflects coal companies that have ceased operations prior to the development of the IRP, but does not forecast the ceasing operations of specific suppliers. The load forecast for coal mining is based on US Energy Information Administration (EIA) forecasts for Central Appalachian coal production and US coal exports. To the extent those EIA forecasts reflect decreased mining operations, those assumptions would be reflected in the Companies IRP modeling.

a. See above response.

b. The Company does not believe the increasing incidence of coal mining company bankruptcies is of little or no concern. The Company is always concerned about the financial wellbeing of all of its customers, and it is monitoring coal mining company bankruptcies within its service territory.

c. KPCO_R_AG_1_02_Attachment1 provides the most recent forecast for mine power energy sales.

d. The Company objects to the form of the question as this request is vague, overbroad, and unduly burdensome. Subject to and without waiving the foregoing objections, the Company states as follows: See KPCO_R_AG_1_02_ConfidentialAttachment2 for the coal price forecasts for the Rockport and Mitchell plants that were used in the Company's 2019 Integrated Resource Plan Filing.

e. The Company is aware of Moody's Investors Services analysis of the coal industry in the U.S. However, the report is proprietary and the Company is not permitted to share per the terms of the contract.

Witness: John F. Torpey

Kentucky Power Company
Mine Power Energy Sales (GWh)

Year	Energy
2018	352
2019	325
2020	287
2021	287
2022	309
2023	307
2024	311
2025	310
2026	310
2027	309
2028	309
2029	308
2030	308
2031	308
2032	308
2033	308
2034	309

DATA REQUEST

AG 1-03 In the event the Company decides to pursue more detailed analysis regarding PPAs, including any additional filings with the Commission, explain to what extent transmission costs, including uplift and congestion, enter into the Company's decision making process.

RESPONSE

A resource acquisition analysis will include any known and forecasted costs, including known and forecasted transmission costs, to provide the resource attributes to the Company's customers over the expected life of the resource.

Witness: John F. Torpey

DATA REQUEST

AG 1-04 In the event the Company should decide at some future point in time to construct a new gas-fired combined cycle plant, provide an estimate for the time required from the plan's inception until the date such a plant can become commercially operable.

RESPONSE

Within this IRP, the Company estimates approximately 5 years from inception to commercial operation for a new gas-fired Combined Cycle plant.

Witness: John F. Torpey

Kentucky Power Company
KPSC Case No. 2019-00443
Attorney General's First Set of Data Requests
Dated April 9, 2020

DATA REQUEST

AG 1-05 Provide a discussion regarding the extent to which the Company has examined the potential for both: (i) building and owning its own renewable generation sources within its service territory; and/or (ii) entering into PPAs for renewable generation from other sources, whether located inside or outside its service territory. With regard to resources outside its territory, explain how congestion or the risk of congestion could affect the cost and benefits in determining resource decisions.
a. Has the Company, or any entity acting on its behalf, conducted any studies or analyses of the cost impact of congestion with regard to entering into any external PPAs for renewable energy or other resources? If so, provide copies of all such studies.

RESPONSE

For this IRP, the Company evaluated owning all resource options.
If and when the Company pursues the acquisition of new or incremental generating or demand-side resources, the Company may consider alternative ownership structures, as well as the forecasted cost of delivery for each alternative, at that time. For this IRP, all resource options are estimated/forecasted to be either within the Company's service territory or to have the ability to deliver the products to the Company. Within the IRP, all generating resources are assumed to be PJM-interconnected resources. Congestion was not modeled in the IRP.

a. No. No such studies have been performed by or for the Company. Congestion will be considered when the Company seeks to acquire wind resources, or enter into a purchase power agreement for wind resources.

Witness: John F. Torpey

DATA REQUEST

AG 1-06 With regard to the cost-effectiveness of continuing to use existing coal-fired generation assets as opposed to switching to renewable sources of generation, state whether the IRP modeling examines both a coal plant's marginal cost of energy, and a renewable source's lower, levelized cost of energy.

RESPONSE

IRP modeling includes the existing generating units' marginal cost of energy and the costs of new resource options, including renewable resources. The IRP model determines the cost to meet the Company's load obligation within PJM. Each resource's costs are evaluated against the cost of both energy and capacity within the PJM market or the Company's Fundamental Commodity Forecasts. The IRP model will not retire an existing generating unit based on its cost relative to the market cost or an alternative new resource.

Witness: John F. Torpey

DATA REQUEST

AG 1-07 Explain whether fixed O&M and capital costs are: (i) factored into the calculation of revenue requirements for any of the scenarios modelled in the IRP, and if not, why not;
(ii) impacted by the scenarios evaluated; and
(iii) considered when assessing whether to retire existing units.
a. If fixed O&M and capital costs are not taken into consideration, explain whether this is consistent with the Commission's requirement to take into consideration the impact of existing and future environmental regulations.

RESPONSE

(i) Specific to the Revenue Requirement analysis performed for this IRP, fixed O&M and capital costs are included.

(ii) Fixed O&M and capital costs are impacted by the scenario evaluated to the extent there is a change in expansion plans. No existing units assumption changes were modeled in this IRP.

(iii) The IRP does not specifically assess whether to retire an existing unit, but instead, analyzes scenarios where an existing unit might be retired. For the scenarios modeled, fixed O&M and capital costs are included to analyze the Cumulative Present Worth (CPW) in order to identify the least cost option.

a. See responses to (i) and (iii) above.

Witness: John F. Torpey

DATA REQUEST

AG 1-08 For purposes of comparing noncombustible renewable energy generation to fossil fuel generation sources, and costs attendant with both forms of generation, explain whether KPCo's modelling compares energy consumption based on the fossil fuel equivalence approach, or the captured energy approach as discussed in more detail in the EIA publication accessible at the below-referenced link. https://www.pressreleasepoint.com/eia-offers-two-approaches-compare-renewable-electricity-generation-other-sources

RESPONSE

The IRP modelling is most closely aligned to the captured energy approach as discussed in the referenced EIA publication.

Witness: John F. Torpey

DATA REQUEST

AG 1-09 Explain how the Company's IRP modeling takes into consideration the continuing costs of complying with state and federal environmental regulations for coal-fired generating plants, including but not limited to ash storage and ash pond remediation/reclamation.
a. Provide any year-over-year inflation factors and discount rates used in estimating costs for environmental compliance with regard to coal-fired generation, including ash storage and ash pond remediation/reclamation.
b. Provide a discussion of how the year-over-year inflation factors and discount rates for environmental compliance with regard to coal-fired generation, including ash storage and ash pond remediation/reclamation are taken into consideration in considering the costs and benefits of continued operation of coal-fired plants, as opposed to obtaining other power sources.

RESPONSE

For this IRP, the Company assumed the existing owned solid-fuel generating resources to be available over the planning period. The incremental capital cost of compliance with current state and federal environmental regulations is included for these resources. Furthermore, the Company did consider and evaluate the cost compliance to both state and federal environmental regulations through both the Fundamentals Commodity Forecast (e.g. cost of carbon) and unit variable O&M impacts (e.g. cost of consumables for SO_2 and NO_x control). However, this IRP assumed that the coal-fired Mitchell Plant would remain in operation over the planning period in all scenarios, the ongoing costs for the Mitchell Plant are the same for all resource portfolios.

a. A 3% escalation is applied to the annual cash flows for the respective environmental compliance capital projects referenced.

b. Not applicable. The Company did not evaluate a Mitchell retirement scenario.

Witness: John F. Torpey

DATA REQUEST

AG 1-10 Produce the most recent estimate that the Company has prepared or caused to be prepared of the capital and O&M costs to comply with the following regulations:
a. Mercury and Air Toxics Standards;
b. Coal Combustion Residuals rule;
c. Effluent Limitations Guidelines;
d. 316(b) cooling water intake rule;
e. NAAQS, including any new ozone standard, including any standards still in the draft stages or which are still open to public comment;
f. Cross State Air Pollution Rule;
g. Carbon regulations, including the Clean Power Plan and the Affordable Clean Energy Plan;
h. Any applicable state environmental regulations;
i. Any other federal environmental regulation; and
j. Pending enforcement actions by citizen groups or regulatory agencies of any state and/or federal environmental requirements.

RESPONSE

The Company objects to this request because it is vague, ambiguous, and would require the company to speculate as to the outcome of pending litigation, and with respect to the outcome of numerous pending regulatory activities, including ongoing reviews of the National Ambient Air Quality Standards (NAAQS), pending amendments to the requirements of the Coal Combustion Residuals (CCR) and Effluent Limitations Guidelines (ELG) regulations, the remand of the Cross State Air Pollution Rule (CSAPR), other ongoing state and federal rulemakings.

Without waiving the foregoing objections, please see KPCO_R_AG_1_10_ConfidentialAttachment1. The information contained in the attachment is confidential information and contains financial projections of future estimated costs that are subject to change, and which have not otherwise been publicly disclosed.

The projections have been separated into costs associated with air programs, water programs, and solid waste management programs. It is not possible to assign costs based on a specific regulation since capital investments and operation and maintenance (O&M) expenses are often incurred to satisfy multiple regulatory requirements. The regulatory requirements and the related capital and O&M costs addressed in each of the three major categories are briefly addressed below:

Air Program Requirements and Costs: These requirements include the Mercury and Air Toxics Standards, state and federal requirements necessary to achieve and maintain the current NAAQS, the existing CSAPR, and other known requirements of state and federal law. It also includes costs associated with air program enforcement actions that have been resolved, such as the implementation of the NSR Consent Decree. The states in which Kentucky Power's units are located have not yet finalized any performance standards for carbon dioxide emissions from power plants, and the Clean Power Plan has been repealed. The costs included in these projections generally pertain to the completion, operation and maintenance of the major controls installed at the plants, including Electrostatic Precipitators (ESPs), Selective Catalytic Reduction (SCR) systems, Flue Gas Desulfurization (FGD) systems, Dry Sorbent Injection (DSI) systems, Activated Carbon Injection (ACI) systems, and associated equipment.

Water Program Requirements and Costs: These requirements would include the implementation of the final ELGs, expenses associated with the §316(b) cooling water intake requirements, and other known state and federal requirements implementing the Clean Water Act. These costs generally reflect upgrades to and operation of wastewater treatment systems and known requirements of state and federal law addressing the quality of wastewaters discharged from our facilities. Kentucky Power does not anticipate significant expenditures associated with the §316(b) program, but may incur expenses for FGD wastewater and other ELG standards. These costs do not include costs required to close surface impoundments or other remedial measures associated with coal ash management units.

Solid Waste Management Programs: These programs include state and federal programs specifying requirements for surface impoundments and landfills used to manage coal ash and FGD by-products, including the CCR rules. Costs to close unlined surface impoundments, ongoing operations and monitoring, post-closure care, remediation, and planned expansions of landfills at coal-fired units are typical costs included for these programs.

Witness: John F. Torpey

See the Company's response to this data request, AG 1-10, for a full description of these costs.

		Year								
Cost Type	**Regulation**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Capital	Air	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Water	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Solid Waste	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
O&M	Air	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Water	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Solid Waste	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

* Kentucky Power's Unit Power Agreement with the Rockport Plant terminates in December 2022

DATA REQUEST

AG 1-11 State whether the IRP modelling takes into consideration estimates for gas transportation, and if so, whether estimates are prepared for both firm and interruptible transportation.

RESPONSE

For this IRP, the natural gas fired resources include an estimated cost for firm gas transportation. Estimates were not developed for interruptible transportation.

Witness: John F. Torpey

DATA REQUEST

AG 1-12 Demonstrate where in the IRP filing the Company addressed affordability of electricity rates, and if so, how.

RESPONSE

The Company describes the impact of the Preferred Plan on electricity rates in Sections 5.3.3 and 5.3.4 of the IRP.

Witness: Brian K. West

Witness: John F. Torpey

DATA REQUEST

AG 1-13 Identify any counties in KPCo's service territory which are projected to lose population, and provide the projected losses over the next ten (10) years.

RESPONSE

KPCO_R_AG_1_13_Attachment1 provides the counties in Kentucky Power Company's service territory that are projected to lose population over the next ten years.

Witness: John F. Torpey

Kentucky Power Company
Counties in Service Area with Projected Population Decline

Year	Boyd	Breathitt	Carter	Floyd	Greenup	Johnson	Knott	Lawrence
2019	47,758	12,636	27,081	35,690	35,301	22,492	15,024	15,718
2020	47,712	12,514	27,048	35,503	35,250	22,441	14,947	15,720
2021	47,687	12,408	26,997	35,319	35,213	22,381	14,886	15,716
2022	47,660	12,327	26,949	35,164	35,197	22,327	14,852	15,720
2023	47,642	12,261	26,898	35,013	35,198	22,275	14,833	15,723
2024	47,628	12,204	26,860	34,869	35,200	22,227	14,820	15,723
2025	47,603	12,158	26,814	34,728	35,205	22,177	14,811	15,720
2026	47,580	12,117	26,765	34,568	35,214	22,112	14,805	15,716
2027	47,557	12,080	26,717	34,403	35,226	22,038	14,800	15,704
2028	47,535	12,046	26,659	34,246	35,238	21,957	14,794	15,691
2029	47,518	12,015	26,598	34,102	35,254	21,867	14,788	15,675
2030	47,506	11,987	26,536	33,965	35,272	21,783	14,782	15,658
2019-2020 Change								
Count	-252	-649	-545	-1,725	-29	-709	-243	-61
Percentage	-0.5%	-5.1%	-2.0%	-4.8%	-0.1%	-3.2%	-1.6%	-0.4%

Year	Leslie	Letcher	Lewis	Magoffin	Martin	Morgan	Pike
2019	10,092	21,994	13,272	12,422	11,265	13,038	57,816
2020	9,996	21,873	13,236	12,365	11,150	12,955	57,490
2021	9,904	21,776	13,196	12,306	11,012	12,875	57,237
2022	9,829	21,710	13,155	12,255	10,892	12,802	57,069
2023	9,761	21,661	13,112	12,200	10,784	12,728	56,954
2024	9,702	21,627	13,075	12,150	10,683	12,660	56,876
2025	9,649	21,600	13,041	12,092	10,591	12,596	56,820
2026	9,600	21,575	13,011	12,033	10,505	12,540	56,777
2027	9,554	21,556	12,980	11,976	10,425	12,480	56,743
2028	9,512	21,541	12,948	11,923	10,349	12,426	56,710
2029	9,475	21,529	12,920	11,875	10,277	12,377	56,681
2030	9,442	21,516	12,887	11,823	10,213	12,326	56,654
2019-2020 Change							
Count	-651	-478	-385	-599	-1,052	-711	-1,162
Percentage	-6.4%	-2.2%	-2.9%	-4.8%	-9.3%	-5.5%	-2.0%

Source; Moody's Analytics December 2018

DATA REQUEST

AG 1-14 Explain whether any of the Company's generating and/or transmission facilities are required to meet any North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection standards. If so:
a. explain whether the Company's generating facilities have been designated as low, medium or high impact;
b. provide the costs of meeting such standards (both initial and on-going costs), and how they are calculated into the overall costs of these facilities; and
c. explain whether those costs are significant enough for them to be taken into consideration in the IRP modeling, and if so, how.

RESPONSE

a. The Company's generating and transmission facilities are required to meet NERC Critical Infrastructure Protection (CIP) standards according to the assessed impact rating per facility. All Kentucky Power generating facilities, after analysis according to NERC CIP-002, contain only Low Impact BES Cyber Systems and Assets.

b. AEP manages NERC compliance, a mandatory legal obligation, at an enterprise level through a centralized, dedicated team focused on core aspects of the program (policy, process and procedure management, project management, and audit and incident management). Also, Transmission, Generation, IT, and Security (physical and cyber) business units have staff dedicated to NERC compliance for their respective obligations. The centralized expenses for NERC compliance allocated to Kentucky Power in 2018 and 2019 were $180,000 and $373,000, respectively. Current year expenses through March 31, 2020 total $138,000. The year-over-year increase in compliance costs is largely due to the implementation of NERC CIP requirements for Low impact BES Cyber Systems and increased compliance assurance activities. These are costs of service dedicated to NERC Compliance. Additionally, NERC Compliance costs are embedded in the ongoing support and operations of generating and transmission facilities as a general cost of business. This embedded cost is neither directly identified in, nor material to, the Company's IRP modeling.

c. The cost of NERC CIP compliance is not a decision factor in IRP modeling because 1) the direct compliance costs are not significant and 2) the same NERC compliance costs will be incurred under all IRP scenarios, and therefore do not create any differential when comparing any scenario versus another.

Witness: John F. Torpey

Kentucky Power Company
KPSC Case No. 2019-00443
Attorney General's First Set of Data Requests
Dated April 9, 2020

DATA REQUEST

AG 1-15 Provide the projected peak load forecast for each year since the date of the Company's last IRP filing. Provide also the actual peak load for each of the last three (3) years.

RESPONSE

KPCO_R_AG_1_15_Attachmentt1 provides the requested information.

Witness: John F. Torpey

Kentucky Power Company
Peak Demand Forecasts, Actual and Weather Normal Peaks (MW)

	Load Forecasts					
Year	**2016**	**2017**	**2018**	**2019**	**Actual**	**Normal**
2017	1,335				1,214	1,332
2018	1,322	1,314			1,446	1,355
2019	1,318	1,296	1,329		1,297	1,315
2020	1,307	1,303	1,339	1,295	1,168	1,279
2021	1,310	1,295	1,362	1,293		
2022		1,288	1,354	1,288		
2023			1,347	1,280		
2024				1,273		

DATA REQUEST

AG 1-16 Provide the following historical annual data by generating unit, from 2010 to present:
a. Fixed O&M cost;
b. Variable O&M cost (without fuel);
c. Fuel costs;
d. Capital costs;
e. Capacity factor; and
f. Generation in kWh.

RESPONSE

See KPCO_R_AG_1_16_Attachment1 for the requested information. Please note all costs reflect 100% of each unit.

Witness: Brian K. West

Witness: John F. Torpey

Kentucky Power Company
KPSC Case No. 2019-00443
Attorney General's First Set of Data Requests
Dated April 9, 2020

DATA REQUEST

AG 1-17 Provide the Company's off-system sales for each of the past three (3) years.

RESPONSE

See KPCO_R_AG_1_17_Attachment1 for the requested information.

Witness: Brian K. West

Kentucky Power Off-System Sales ($)
2017-2019

Account	Year		
	2017	2018	2019
4470001	(1,435,823.80)	(174,444.96)	
4470006	(5,458,609.01)	(5,030,063.07)	(10,311,778.11)
4470010	4,834,961.03	6,650,074.36	9,857,988.83
4470081	27,040.15	24,870.46	10,832.98
4470082	668,775.27	(181,873.40)	1,743,263.21
4470089	(11,380,818.48)	(10,345,900.77)	(3,957,620.42)
4470098	52,400.73	104,246.19	8,551.85
4470099	(2,177,192.50)	(1,259,354.15)	(2,422,966.19)
4470100	(215,951.33)	(790,285.59)	(459,065.07)
4470107	(27.43)	9.35	(1.55)
4470110	0.18	8.27	0.69
4470112	(572,498.06)	(1,362,297.58)	(928,358.73)
4470115	923.40	(53,354.96)	4,110.94
4470126	256,718.52	1,989,534.75	29,947.91
4470131	1,862,773.91	1,723,220.34	868,082.83
4470143	(1,442,692.84)	1,027,655.88	(1,656,696.91)
4470151	-	(933,325.13)	(2,069,395.47)
4470168	(42.60)		
4470206	(249,595.94)	(271,232.25)	(68,917.34)
4470209	1,570,317.39	1,336,676.10	696,425.09
4470214	44,805.79	(145,320.08)	(62,315.72)
4470215	(2,346.91)	86,893.00	32,574.60
4470220	(95,141.13)	(415,261.77)	(721,836.83)
4470221	1,671.61	(29,425.52)	(23,399.81)
4470222	329,377.30	(558.13)	(178,482.97)
5550039	14,933.22	6,996.65	1,889.73
5550099	(2,600.33)	(837.17)	(126.17)
5570007	37,408.95	22,525.89	85,420.87
5614000	178,453.24	134,451.41	131,446.72
5618000	59,685.39	38,776.41	34,862.59
5757000	204,452.97	127,295.34	126,331.06
Grand Total	**(12,888,641.31)**	**(7,720,300.13)**	**(9,229,231.39)**

DATA REQUEST

AG 1-18 Provide the Company's current order of economic dispatch, and the dispatch rate for each generating unit.

RESPONSE

Please see KPCO_R_AG_1_18_Attachment1 for the requested information for April 2020. The Company interprets "dispatch rate" to mean the net capacity factor.

Witness: John F. Torpey

Unit Names	Dispatch Order	From Month	To Month	Net Capacity Factor
Big Sandy Unit 1	1	Apr-20	Apr-20	17.82%
Rockport Unit 1	2	Apr-20	Apr-20	43.82%
Rockport Unit 2	3	Apr-20	Apr-20	0.00%
Mitchell Unit 1	4	Apr-20	Apr-20	15.34%
Mitchell Unit 2	5	Apr-20	Apr-20	0.00%

DATA REQUEST

AG 1-19 Provide a description of all on-going supplemental transmission expansion plans3 the Company has, as well as those for the next three (3) years, together with cost projections for each project.
a. Provide a description of all supplemental transmission expansion projects the Company has had for the last three (3) years, together with: (i) costs for each project; and (ii) any cost performance studies.
b. Provide an asset management plan that includes a forecast of the expected costs for each supplemental transmission project over the next five (5) years.
c. Provide an estimate of the transmission capital investment over the next five (5) years.
d. For each supplemental transmission project scheduled for the next five (5) years, provide a description of whether the investment is for new infrastructure, or for maintenance of existing facilities.
e. Provide cost-benefit analyses for each supplemental transmission project scheduled for the next five (5) years.
f. For each supplemental transmission project scheduled for the next five (5) years, identify the quantifiable benefits expected to be achieved.
g. Explain whether each supplemental transmission project scheduled for the next five (5) years will be competitively bid. If not, explain fully why not.

RESPONSE

The Company objects to this request as seeking information that is outside the scope of this case and which is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence regarding the Company's load projections and future resource actions. The Company further objects to the extent the request is vague, overbroad, and unduly burdensome. The Company also objects to the phrases "cost performance studies" in subpart a., "cost-benefit analyses" in subpart e., "quantifiable benefits" in subpart f., and "competitively bid" in subpart g. on the grounds that those phrases are vague and ambiguous. Subject to and without waiving the foregoing objections, the Company states as follows:

a.-d. A description of the Company's previous, on-going, and planned supplemental transmission projects, including the anticipated cost of each project, is available on the PJM website at the following link: https://www.pjm.com/planning/project-construction. Project specific information can be found by clicking the links embedded in the PJM tracker.

e. The requested analysis has not been performed. The drivers of supplemental transmission projects may vary to address asset performance, condition, and risk as well as serving new customers, and addressing safety concerns. These drivers are not readily translated into economic values.

f. The requested analysis has not been performed. Please see the Company's response to subpart e.

g. The decision to competitively bid any or all aspects of a supplemental transmission project is made on a case by case basis. The Company has chosen to competitively bid aspects of each of the projects available on the PJM tracker website above, which may include certain materials (such as transmission structures) and construction labor. Please also see the Company's response to KPSC 1-33.

Witness: John F. Torpey

DATA REQUEST

AG 1-20 Provide the Company's total congestion charges incurred for the last complete calendar or fiscal year such charges are available. Also provide congestion cost projections for the next five (5) years.

RESPONSE

Please see KPCO_R_AG_1_20_Attachment1 for the requested information.

Witness: John F. Torpey

Kentucky Power Company
Congestion Costs
Amounts in ($000)

		Actual	Forecast				
Account	Description	2019	2020	2021	2022	2023	2024
4470126	PJM Incremental Imp Cong-OSS	(30)	(734)	(636)	(555)	(555)	(555)
5550124	PJM Implicit Congestion-LSE	8,881	13,570	13,570	13,570	13,570	13,570

Kentucky Power Company
KPSC Case No. 2019-00443
Attorney General's First Set of Data Requests
Dated April 9, 2020

DATA REQUEST

AG 1-21 Explain whether KPCo utilizes, or has considered utilizing, dynamic transmission line ratings as opposed to static transmission line ratings.

RESPONSE

The Company does not currently use Dynamic Transmission Line Ratings. The Company uses seasonal static ratings in long-term transmission planning and a form of Ambient Adjusted ratings for transmission operations, which is consistent with PJM's line rating methodology.

Witness: John F. Torpey

DATA REQUEST

AG 1-22 With regard to any supply side renewable resources, provide a detailed explanation of whether the Company took hydro power into consideration, and if so, how. If not, explain fully why not. Include in your explanation whether Canadian hydro power resources were examined.

RESPONSE

Section 4.5.6.3 of the IRP discusses that no incremental hydroelectric resources were considered in this IRP due to lengthy development time for environmental studies, permitting, high up-front construction costs and environmental issues. However, the Company is open to considering competitive proposals from entities such as Canadian hydro power resources during a resource acquisition analysis.

Witness: John F. Torpey

DATA REQUEST

AG 1-23 Reference the executive summary at p. ES-2. Confirm that over the instant IRP's 15-year forecast period:
a. KPCo is projected to lose 6% of its customer count; b. Retail sales to residential class customers are projected to decline by a total of 7.5%.

RESPONSE

Between 2020 and 2034, the Company projects it will lose 5.3% of the residential customers and that residential energy sales will decrease by 6.8%.

Witness: John F. Torpey

DATA REQUEST

AG 1-24 Reference the executive summary at p. ES-2, the sentence that reads: "Finally, Kentucky Power's internal energy is projected to show little growth and peak demand is expected to decline at an average rate of 0.2% through 2034."
a. Explain whether the projected decline in peak demand is for an average of 0.2% for each year through and including 2034.

RESPONSE

The 0.2% reflects the compound annual growth rate through 2034.

Witness: John F. Torpey

DATA REQUEST

AG 1-25 Reference the executive summary at p. ES-2. Explain how the Company determined Big Sandy 1 (BS-1) 's projected termination date to be 2030.
a. Has the Company conducted any studies, including but not limited to depreciation studies, regarding BS-1's useful lifespan after it was converted to natural gas firing? If so, provide copies or web links to where those documents can be fully accessed.

RESPONSE

Big Sandy 1 (BS-1) has a projected retirement date of 2031. This assumption is consistent with that used in Case No. 2013-00430 in connection with the Company's application for a certificate of public convenience and necessity to convert BS-1.
The Company determined the remaining useful life date for BS-1 through a combination of the use of the previously-approved, pre-conversion depreciation timeframe, and the mechanical reality that the life of the plant is limited by the lives of its critical components such as its turbines, steam drum, generator, and generator step-up transformer (GSU). BS-1 was placed in service in 1963 and still operates with the original turbines, steam drum, generator and GSU. None of its critical components were replaced as part of the conversion from coal to natural gas in 2016. By 2031, these components will be 68 years old and anticipated to be at the end of their useful lives. Accordingly, there have been no significant known changes in the depreciation parameters or assumptions to justify changes to BS-1's depreciation study and projected retirement date.

a. See KPCO_R_AG_1_25_Attachment1 for a December 31, 2016 Depreciation Study for Big Sandy Unit 1.

Witness: John F. Torpey

KENTUCKY POWER COMPANY

DEPRECIATION STUDY REPORT

FOR

BIG SANDY UNIT 1

ELECTRIC PLANT IN SERVICE

AT

DECEMBER 31, 2016

DEPRECIATION STUDY REPORT

Table of Contents

I. INTRODUCTION

This report presents the results of a depreciation study of Kentucky Power Company's ("Kentucky Power" or "Company") depreciable Big Sandy Unit 1 electric utility plant in service at December 31, 2016 (the "Study"). The study was prepared by Jason A. Cash, Staff Accountant – Accounting Policy and Research at American Electric Power Service Corporation ("AEPSC"). The purpose of the Study was to develop updated annual depreciation accrual rates for Unit 1 of Kentucky Power's Big Sandy Plant.

The proposed depreciation rates are based on the Average Remaining Life Method of computing depreciation. Further explanation of this method is contained in Section II of this report.

The definition of depreciation used in the Study is the same used by the Federal Energy Regulatory Commission ("FERC") and the National Association of Regulatory Utility Commissioners and in preparing the Company's most recent depreciation study in Case No. 2014-00396:

> Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.
>
> Service value means the difference between original cost and the net salvage value (net salvage value means the salvage value of the property retired less the cost of removal) of the electric plant. (FERC Accounting and Reporting Requirements for Public Utilities and Licensees, ¶15.001.)

Schedule I of this report shows the proposed depreciation accrual rates for Big Sandy Unit 1. Schedule II compares depreciation expense of Big Sandy Unit 1 using rates approved by the Commission and rates recommended by the depreciation study. A comparison of Kentucky

Power's current rates and accruals for Big Sandy Unit 1 and the Study rates and accruals is shown below based on total Company depreciable plant balances at December 31, 2016:

Table 1 - Depreciation Rates and Accruals
Based on Depreciable Plant In Service at December 31, 2016

	Existing		Study		
Functional Plant Group	Rates	Accruals	Rates	Accruals	Difference
Big Sandy Unit 1	3.78%	5,886,810	5.78%	9,003,728	3,116,918

Based on Big Sandy Unit 1 Depreciable Plant In-Service as of December 31, 2016, the Company proposes an increase in depreciation rates that result in an increase in annual depreciation expense of $3,116,918. The depreciation rate changes are necessary because of changes in investment and the service life of Big Sandy Unit 1 after it was converted to use natural gas in 2016. Big Sandy Unit 1's current depreciation rates are based on a 1991 settlement agreement in Case No. 91-066 and were made effective on April 1, 1991.

II. DISCUSSION OF METHODS AND PROCEDURES USED IN THE STUDY

1. Group Method

All of the depreciable property included in the Study was considered using the group plan method. Under the group plan method, depreciation expense is accrued upon the basis of the original cost of all property included in each depreciable plant account. Upon retirement of any depreciable property, its full cost, less any net salvage realized, is charged to the accrued depreciation reserve regardless of the age of the particular item retired. Also, under the group plan method, the amount in each primary plant account are considered as a separate group for depreciation accounting purposes and an annual depreciation rate for each account is determined. The annual accruals by primary account were then summed, to arrive at the total accrual for each functional group. The total accrual divided by the original cost yields the functional group accrual rate.

2. Annual Depreciation Rates Using the Average Remaining Life Method

Kentucky Power's current depreciation rates are based on the Average Remaining Life Method. The Average Remaining Life Method recovers the original cost of the plant, adjusted for net salvage, less accumulated depreciation, over the average remaining life of the plant. By this method, the annual depreciation rate for each account is determined on the following basis:

$$\text{Annual Depreciation Expense} = \frac{\text{(Orig. Cost) (Net Salvage Ratio) - Accumulated Depreciation}}{\text{Average Remaining Life}}$$

$$\text{Annual Depreciation Rate} = \frac{\text{Annual Depreciation Expense}}{\text{Original Cost}}$$

3. Life Span Analysis

For Kentucky Power's Big Sandy Unit 1, a life span analysis was used to arrive at the historically realized mortality characteristics and service life of the depreciable plant investment. The life-span method of analysis is particularly suited to specific location property, such as generating plants, where all of the surviving investments are likely to be retired in total at a future date. The key elements in the life span analysis are the age of the surviving investments, the projected retirement date of the facility and the expected interim retirements. Interim retirements are those retirements that are expected to occur between the date of the depreciation study and the expected final retirement date of the generating plant. Examples of interim retirements include fans, pumps, motors, a set of boiler tubes, a turbine rotor, etc. The interim retirement history for each primary production plant account was analyzed and the results of those analyses were used to project future interim retirements. The age of Big Sandy's surviving investments at December 31, 2016 was obtained from the accounting records of Kentucky

Power. AEPSC engineering and Kentucky Power operational personnel provided the estimated retirement date used in the life-span analysis for Big Sandy Unit 1.

Big Sandy Unit 1

At December 31, 2016, Kentucky Power's depreciable investment in Steam Production Plant includes Big Sandy Unit 1. Big Sandy Unit 1 is located on Highway 23 near Louisa, Kentucky and was originally placed in service in 1963. Kentucky Power converted Big Sandy Unit 1 from a coal fired unit to a natural gas fired unit in 2016. Following the conversion to natural gas, Big Sandy Unit 1's capacity is 285 MW. The anticipated retirement date for Big Sandy Unit 1 as a natural gas unit is 2031. Additionally, since the last depreciation study performed for Kentucky Power (property investment dated December 31, 2013), Kentucky Power retired Big Sandy Unit 2 and the coal related assets of Big Sandy Unit 1 in 2015.

III. NET SALVAGE

1. Net Salvage - Steam Production Plant

The net salvage analysis for steam production plant included a review of the experienced functional interim retirement, salvage and removal history for Steam Production Plant for the period 2001-2016.

While the net salvage characteristics include interim retirements for the plants, the most significant net salvage amounts for generating plants occurs at the end of their life. Therefore, to assist in establishing total net salvage applicable to Kentucky Power's Big Sandy Unit 1, Kentucky Power relied on a conceptual demolition costs estimate prepared by Sargent & Lundy for the Big Sandy Plant. The Sargent & Lundy demolition cost estimates are based on 2013 price levels which were inflated to retirement date in the depreciation study. The terminal net salvage amount provided by Sargent & Lundy in the dismantling study was for the entire Big Sandy Plant, which included both Units 1 and 2. A portion of the terminal net salvage amount was allocated to Unit 1 based on the generating capacity of each unit. These estimates were incorporated into the calculation of net salvage ratios for Big Sandy's Production Plant.

2. Net Salvage – Ratios

The net salvage ratios shown on Schedule I of this report may be explained as follows:

a. Where the ratio is shown as unity (1.00), it was assumed that the net salvage in that particular account would be zero.

b. Where the ratio is less than unity, it was assumed that the salvage exceeded the removal costs. For example, if the net salvage were 20%, the net salvage ratio would be expressed as .80.

c. Where the ratio is greater than unity, it was assumed that the salvage was less than the cost of removal. For example, if the net salvage were minus 5%, the net salvage ratio would be expressed as 1.05.

IV. STUDY RESULTS

Steam Production Plant

Depreciation rates for Big Sandy Unit 1 were calculated by plant account with the expectation that the total cost including interim net salvage would be recovered by 2031, which is the estimated retirement date for the unit. A comparison of the Big Sandy Unit 1 steam production depreciation accruals is provided on Schedule II using the currently approved depreciation rates and the study depreciation rates. The original cost and accumulated depreciation amounts used for Big Sandy Plant are the plant's original cost and accumulated depreciation on Kentucky Power's books at December 31, 2016.

Depreciation rates for the Big Sandy Plant increased from 3.78% to 5.78%. As a result, depreciation expense increased by $3,116,918. The increase in steam production depreciation expense due to the change in depreciation rates was primarily because of the changes in investment and the service life of Big Sandy Unit 1 after it was converted to use natural gas in 2016.

SCHEDULE I – EXPLANATION OF COLUMN HEADINGS

Schedule I shows the determination of the recommended annual depreciation accrual rate by primary plant accounts by the straight line remaining life method. An explanation of the schedule follows:

Column I	-	Account number.
Column II	-	Account title.
Column III	-	Original Cost at December 31, 2016
Column IV	-	Net Salvage Ratio.
Column V	-	Total to be Recovered (Column III) * (Column IV).
Column VI	-	Calculated Depreciation Requirement.
Column VII	-	Accumulated Depreciation.
Column VIII	-	Remaining to be Recovered (Column V - Column VII).
Column IX	-	Average Remaining Life.
Column X	-	Recommended Annual Accrual Amount.
Column XI	-	Recommended Annual Accrual Percent or Depreciation Rate (Column X/Column III).

KENTUCKY POWER COMPANY
SCHEDULE I - CALCULATION OF BIG SANDY UNIT 1 DEPRECIATION RATES BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2016
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

Acct.	Title	Original Cost	Net Salvg. Ratio	Total to be Recovered	Calculated Depreciation Requirement	Accumulated Depreciation	Remaining to Be Recovered	Avg. Remain Life	Annual Accrual Amount	Annual Accrual Percent
(I)	(II)	(III)	(IV)	(V)	(VI)	(VII)	(VIII)	(IX)	(X)	(XI)
STEAM PRODUCTION PLANT										
Big Sandy Unit 1										
311.0	Structures & Improvements	11,756,127	1.09	12,814,178	7,526,502	4,805,397	8,008,781	14.10	567,999	4.83%
312.0	Boiler Plant Equipment	75,388,722	1.09	82,173,707	22,552,265	9,774,280	72,399,427	13.43	5,390,873	7.15%
314.0	Turbogenerator Units	61,392,346	1.09	66,917,657	36,338,075	28,424,981	38,492,676	13.86	2,777,249	4.52%
315.0	Accessory Electrical Equip.	3,877,136	1.09	4,226,078	2,964,549	2,578,951	1,647,127	14.03	117,400	3.03%
316.0	Misc. Power Plant Equip.	3,321,344	1.09	3,620,265	2,153,127	1,512,867	2,107,398	14.03	150,207	4.52%
	Total	155,735,675		169,751,885	71,534,518	47,096,476	122,655,409		9,003,728	5.78%
	Total Depreciable Plant	155,735,675	1.09	169,751,885	71,534,518	47,096,476	122,655,409	13.62	9,003,728	5.78%

N/A = Not Applicable

KENTUCKY POWER COMPANY
SCHEDULE II - COMPARE BIG SANDY UNIT 1 DEPRECIATION EXPENSE USING CURRENT AND STUDY RATES
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2016

NO. (1)	TITLE (2)	ORIGINAL COST AT 12/31/2015 (3)	CURRENT APPROVED RATE (4)	ANNUAL ACCRUAL (5)	STUDY RATE (6)	STUDY ACCRUAL (7)	DIFFERENCE (DECREASE) (8)
STEAM PRODUCTION PLANT							
BIG SANDY UNIT 1							
311.0	Structures & Improvements	11,756,127	3.78%	444,382	4.83%	567,999	123,617
312.0	Boiler Plant Equipment	75,388,722	3.78%	2,849,694	7.15%	5,390,873	2,541,179
314.0	Turbogenerator Units	61,392,346	3.78%	2,320,631	4.52%	2,777,249	456,618
315.0	Accessory Electrical Equipment	3,877,136	3.78%	146,556	3.03%	117,400	(29,156)
316.0	Misc. Power Plant Equip.	3,321,344	3.78%	125,547	4.52%	150,207	24,660
	Total	155,735,675	3.78%	5,886,810	5.78%	9,003,728	3,116,918
	Total Depreciable Plant	155,735,675	3.78%	5,886,810	5.78%	9,003,728	3,116,918

DATA REQUEST

AG 1-26 Reference the executive summary at p. ES-4, and IRP § 1.5. Confirm that the Preferred Plan calls for a new 122 MW "aeroderivative" natural gas unit to be constructed in 2031.
a. Explain the meaning of the term "aeroderivative." Explain also how this type of gas plant would differ from a standard combined cycle natural gas plant.
b. If there are differences between the two types of gas plants, explain whether the IRP's modelling took standard combined cycle natural gas units into consideration.

RESPONSE

The Preferred Plan includes a new 122 MW aeroderivative (AD) natural gas fired unit to be commercially available in 2031.

a. Section 4.5.4.2 of the IRP explains the meaning of the term "aeroderivative" generating unit. One particular primary difference to a standard combined cycle natural gas plant is the AD does not utilize the waste heat to generate steam.

b. The IRP modeling included a Combined Cycle (CC) plant as an available resource, as described in Section 5.2.1.

Witness: John F. Torpey

DATA REQUEST

AG 1-27 Reference Table ES-1.
a. Confirm that in 2020 and 2021, the Company will have reserves of 236 MW and 232 MW, respectively.
b. Confirm that in 2022 and 2023, the Company's reserves will drop to 11 MW and 15 MW, respectively.
c. Provide the reserve margin PJM will require the Company for each year from 2020 through and including 2024.
d. Explain whether the Company could face PJM fines or penalties if it fails to maintain reserves in accordance within PJM requirements.
e. Explain whether the significantly lower reserve margins beginning in 2022 exposes the Company to greater risk of having to rely upon market purchases. If so, provide any studies or analyses the Company may have conducted regarding this risk, and any monetary quantifications thereof.
f. Explain whether the Company is aware of any other LSEs within the PJM footprint that do or will maintain reserves as low as KPCo's projected reserve margins beginning in 2022.

RESPONSE

a.-b. Confirmed, this is the Company's planned reserve above the PJM required reserve margin.

c. The following table illustrates the required PJM Installed Reserve Margin for the PJM Planning Years:

Year	PJM Installed Rsrv Margin
2020	16.00%
2021	15.90%
2022	15.80%
2023	15.70%
2024	15.70%

d. Yes, the Company would incur fines and penalties if reserves are not maintained in accordance with PJM requirements.

e. The Company has not conducted the requested analysis. The Company's IRP projects that short term market purchases are an economically efficient resource in the near term to meet reserve margin requirements.

f. The reserve margins are comparable to those of other AEP affiliates. The Company is not aware of reserve margins of non-affiliated LSEs'.

Witness: John F. Torpey

DATA REQUEST

AG 1-28 Reference p. ES-5, wherein it is stated that the Preferred Plan selects Short-Term Market Purchases (STMP) for capacity obligations following the expiration of the Rockport UPA in December 2022.
a. Explain whether the STMPs would be at fixed prices. If not, explain whether the Company considered hedging the prices for STMPs. With regard to any such hedging, provide all relevant studies and analyses.
b. Identify all other alternatives to STMPs that were examined.
c. Explain whether the IRP modelling took into consideration the possibility of procuring (whether through the AEP Power Coordination Agreement, or otherwise) any excess capacity that might be available at any one or more plants in which any AEP affiliates have an ownership interest, or in which they otherwise have energy purchase rights.

RESPONSE

a. Section 4.5.5 of the IRP describes the Company's assumption for the STMP resource. The assumption includes an annual fixed price for the resource.

b. For this IRP, all new resources available in the model are described in Section 5.2.1.

c. The IRP modeling did not explicitly consider other AEP affiliates generating resources as resource options for this IRP.

Witness: John F. Torpey

DATA REQUEST

AG 1-29 Reference p. ES-5, wherein it is stated that the Preferred Plan adds 101 MW of utility scale solar (nameplate) in 2023, increasing to a total of 455 MW (nameplate) by 2034.

a. Explain whether the solar power procurements would be self-built or through PPAs.

b. Following the initial deployment of 101 MW of solar in 2023, explain in what size increments the remaining 454 MW of solar power would be built.

c. Reference IRP § 4.7 (4), wherein it is stated that KPCo is in discussions to add approximately 20 MW of solar resources by the end of 2021. Explain whether this 20 MW facility(ies) is part of the initial 101 MW of solar generation referenced at p. ES-5.

d. Explain whether the solar units would be located inside or outside of Kentucky.

e. Explain whether the Preferred Plan took into consideration all transmission costs (including but not limited to congestion charges) associated with renewable energy in any form, including but not limited to congestion charges.

f. Given the intermittent nature of most renewable resources, explain how the Preferred Plan analyzes the need for reliable resources available at each hour, for every day of the year.

(i) Identify any and all supply side resources the Company intends to utilize to back up renewable resources when they are unavailable due to their intermittent nature.

(ii) Explain whether the Preferred Plan's reliance on additional renewable resources would result in increased throttling (backing off the generation output) of the Mitchell and/or BS-1 units. If so, explain whether this would increase O&M costs on those units. If not, why not?

RESPONSE

a. The solar resources that make up the 455 MW (nameplate) of capacity by 2034 are considered as self-built within the model and described in sections 4.5.6.1.1 and 5.2.1.

b. Described in section 4.5.6.1.1, solar resources would be implemented in 50.6 MW installations.

c. The 20MW of solar resources are not part of the initial 101 MW of solar generation referenced.
d. For the IRP planning purposes, the solar resources are assumed to be located inside Kentucky.

e. All resources in the IRP are not location specific, however they do include estimated costs for transmission interconnection. Within this IRP, no additional congestion costs were included.

f-i. The Company's model includes the PJM guidance for the Effective Load Carrying Capacity (ELCC) associated with renewable resources to identify the appropriate amount of capacity required to meet the PJM Installed Reserve Margin. Non-renewable supply side resources included in the IRP to meet KPCo's load are illustrated in Figure ES-7 in the IRP and include Coal and Natural Gas (existing and new) resources.

f-ii. For this IRP, adding the renewable generation in the Company's Preferred Plan to KPCo's generation portfolio did not result in "throttling" of the operating profiles of either the Mitchell or Big Sandy generation resources. All generating resources are dispatched into PJM based on the PJM day-ahead energy prices, not KPCo load.

Witness: John F. Torpey

DATA REQUEST

AG 1-30 Reference p. ES-5, wherein it is stated that the Preferred Plan adds 100 MW (nameplate) of new wind resources in 2028 and an additional 100 MW (nameplate) in 2030.
a. Explain where the wind resources would be located (i.e., whether in Kentucky or in another state).
b. Explain whether the Preferred Plan took into consideration the additional transmission costs (including but not limited to congestion charges) that would be incurred via importing that energy into KPCo's service territory.

RESPONSE

a. For this IRP, the wind resources are assumed to be a PJM resource and a specific resource location has not been identified.

b. The wind resources in the IRP are not location specific, other than that they must be interconnected to the PJM system and are considered to have the ability to deliver their product to the Company at the assumed resource costs. During a resource acquisition process, to the extent there are additional costs associated with a specific wind project, those costs would be considered as part of the evaluation.

Witness: John F. Torpey

DATA REQUEST

AG 1-31 Reference p. ES-5, wherein it is stated that the Preferred Plan adds Volt-Var Optimization. Explain the types and amounts of costs necessary to implement Volt-Var.
a. Explain whether it would be necessary to implement a smart meter program in order to implement significant amounts of Volt-Var.

RESPONSE

Please refer to Section 4.4.3.2 where Volt-VAR Optimization (VVO) is discussed.

a. No, it would not be necessary to implement a smart meter program in order to implement significant amounts of VVO.

Witness: John F. Torpey

Kentucky Power Company
KPSC Case No. 2019-00443
Attorney General's First Set of Data Requests
Dated April 9, 2020

DATA REQUEST

AG 1-32 Reference p. ES-5, wherein it is stated that the Preferred Plan assumes KPCo's customers add 9 MW of distributed generation by 2034. Provide copies of any studies KPCo or any other entity on KPCo's behalf may have conducted regarding the potential for customer-owned DG penetration.
a. Explain how the changes to KRS 278.466 could affect customers' ability to procure distributed generation resources.

RESPONSE

Section 4.4.3.4 in the IRP discusses DG resources in the IRP. Please refer to the footnotes in this section for forecasts used in this IRP.

a. The new rate has yet to be established. Therefore, it is not yet known what the impacts of the legislation would be. At this time, traditional net metering is in place for the Company's customers, and the Company remains below the 1% cap for traditional net metering.

Witness: Brian K. West

Witness: John F. Torpey

DATA REQUEST

AG 1-33 Reference p. ES-5, wherein it is stated that over the 15-year planning period, KPCo's nameplate capacity mix attributable to coal-fired assets would decline from 81% to 49%. Explain whether this means that KPCo will be reducing its ownership interest in the Mitchell units. If so, explain when this is expected to occur, and how.
a. Provide the latest studies, including but not limited to depreciation studies, regarding the Mitchell Units' useful lifespan.
b. Explain whether the IRP considered the option of re-firing the Mitchell units from coal to gas, and if so, whether this was a cost-effective option.
c. Explain whether the IRP took into consideration the costs of ash pond remediation at the Mitchell units. If not, explain why not.

RESPONSE

The change in capacity mix is not attributed to any reduction in ownership interest in the Mitchell units. The reduction is due to the expiration of the Rockport Unit Power Agreement (UPA).

a. For the purposes of this IRP, the Company assumed that the Mitchell Plant would be available through the end of the planning period. See KPCO_R_AG_1_33_Attachment1 for the most recent depreciation study filed by Kentucky Power, dated December 31, 2013. See KPCO_R_AG_1_33_Attachment2 for a depreciation study filed on behalf of Kentucky Power affiliates Appalachian Power Company and Wheeling Power Company, dated December 31, 2017. Wheeling Power Company and Kentucky Power Company each have a 50% ownership interest in the Mitchell Plant.

b. The IRP did not consider the option of re-firing the Mitchell units from coal to gas.

c. Yes, costs related to ash pond remediation projects at the Mitchell units were taken into consideration. See response to AG 1-09.

Witness: John F. Torpey

KENTUCKY POWER COMPANY

DEPRECIATION STUDY REPORT

OF

ELECTRIC PLANT IN SERVICE

AT

DECEMBER 31, 2013

DEPRECIATION STUDY REPORT

Table of Contents

I. INTRODUCTION

This report presents the results of a depreciation study of Kentucky Power Company's (KPCo) depreciable electric utility plant in service at December 31, 2013. The study was prepared by David A. Davis, Manager – Property Accounting Policy and Research at American Electric Power Service Corporation (AEPSC). The purpose of the depreciation study was to develop appropriate annual depreciation accrual rates for each of the primary plant accounts that comprise the functional groups for which KPCo computes its annual depreciation expense.

The recommended depreciation rates are based on the Average Remaining Life Method of computing depreciation. Further explanation of this method is contained in Section II of this report.

The definition of depreciation used in my Study is the same as that used by the Federal Energy Regulatory Commission (FERC) and the National Association of Regulatory Utility Commissioners:

> "Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities."
>
> "Service value means the difference between original cost and the

net salvage value (net salvage value means the salvage value of the property retired less the cost of removal) of the electric plant." (FERC Accounting and Reporting Requirements for Public Utilities and Licensees, ¶15.001.)

Schedule I of this report shows the recommended depreciation accrual rates by primary plant accounts and composited to functional plant classifications. Schedule II compares depreciation expense using rates approved by the Commission and rates recommended by the depreciation study. Schedule III shows a comparison of the current mortality characteristics that were used to compute the recommended depreciation rates and the mortality characteristics used to determine the existing depreciation rates and accruals for Transmission, Distribution and General Plant Functions. A comparison of KPCo's current functional group composite depreciation rates and accruals to recommended functional group rates and accruals based on December 31, 2013 depreciable plant balances follows:

Table 1 - Depreciation Rates and Accruals
Based on Depreciable Plant In Service at December 31, 2013

	Existing		Study		
Functional Plant Group	Rates	Accruals	Rates	Accruals	Difference
Steam Production (1)	3.80%	54,851,796	3.36%	48,418,617	(6,433,179)
Transmission	1.71%	8,478,288	2.66%	13,169,805	4,691,517
Distribution	3.52%	24,312,736	4.48%	30,971,933	6,659,197
General	2.54%	858,462	4.42%	1,492,241	633,779
Total Depreciable Plant	3.32%	88,501,282	3.50%	94,052,596	5,551,314

Note: (1) Includes Big Sandy and Mitchell plants. The Company is not recommending a change in depreciation rates for Big Sandy Plant due to the planned retirement of Unit 2 in 2015 and the coal related portions of Unit 1 in 2016.

Based on Total Company Depreciable Plant In-Service as of December 31, 2013, I am recommending an increase in depreciation rates that result in an increase in annual depreciation expense of $5,551,314. The depreciation rate changes are necessary because of changes in average service lives and net salvage estimates used to calculate KPCo's recommended depreciation rates that takes into account the December 31, 2013 transfer of a 50% undivided interest in the Mitchell generating station from AEP affiliate Ohio Power Company as approved by the Kentucky Public Service Commission (or Commission) in Case No. 2012-00578. KPCo's current approved depreciation rates with the exception of Mitchell Plant rates are based on a 1991 settlement agreement in Case No. 91-066 and were made effective on April 1, 1991. The Stipulation and Settlement Agreement in Case No. 2012-00578 ordered Kentucky Power to use the current Ohio Power Company depreciation rates for Mitchell Plant until such rates are changed in a base rate case.

II. DISCUSSION OF METHODS AND PROCEDURES USED IN THE STUDY

1. Group Method

All of the depreciable property included in this report was considered on a group plan. Under the group plan, depreciation expense is accrued upon the basis of the original cost of all property included in each depreciable plant account. Upon retirement of any depreciable property, its full cost, less any net salvage realized, is charged to the accrued depreciation reserve regardless of the age of the particular item retired. Also, under this plan, the dollars in each primary plant account are considered as a separate group for depreciation accounting purposes and an annual depreciation rate for each account is determined. The annual accruals by primary account were then summed, to arrive at the total accrual for each functional group. The total accrual divided by the original cost yields the functional group accrual rate.

2. Annual Depreciation Rates Using the Average Remaining Life Method

KPCo's current depreciation rates are based on the Average Remaining Life Method. The Average Remaining Life Method recovers the original cost of the plant, adjusted for net salvage, less accumulated depreciation, over the average remaining life of the plant. By this method, the annual depreciation rate for each account is determined on the following basis:

$$\text{Annual Depreciation Expense} = \frac{\text{(Orig. Cost) (Net Salvage Ratio) - Accumulated Depreciation}}{\text{Average Remaining Life}}$$

$$\text{Annual Depreciation Rate} = \frac{\text{Annual Depreciation Expense}}{\text{Original Cost}}$$

3. Methods of Life Analysis

Depending upon the type of property and the nature of the data available from the property accounting records, one of three life analyses was used to arrive at the historically realized mortality characteristics and service lives of the depreciable plant investments. These methods are identified and described as follows:

Life Span Analysis

The life span analysis was employed for Mitchell Plant. The life-span method of analysis is particularly suited to specific location property, such as generating plants, where all of the surviving investments are likely to be retired in total at a future date. The key elements in the life span analysis are the age of the surviving investments, the projected retirement date of the facility and the expected interim retirements. Interim retirements are those retirements that are expected to occur between the date of the depreciation study and the expected final retirement date of the generating plant. Examples of interim retirements include fans, pumps, motors, a set of boiler tubes, a turbine rotor, etc. The interim retirement history for each primary production plant account was analyzed and the results of those analyses were used to project future interim retirements. The age of Mitchell Plant's surviving investments at December 31, 2013 was obtained from the accounting records of affiliate Ohio Power Company (OPCo). American Electric Power Service Corporation (AEPSC) provided the retirement date used in the life-span analysis for Mitchell Plant.

The Company is not recommending any revision to Big Sandy Plant's depreciation rates in this filing since Unit 2 is planned for retirement at the end of May 2015 and the coal related portions of Unit 1 are planned for retirement in April 2016. KPCo expects to repower Big Sandy Unit 1 to use natural gas in 2016.

The order in the Mitchell transfer Case No. 2012-00578 allows Kentucky Power to recover the coal-related retirement costs of Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2 and other site related retirement costs that will not continue in use. New depreciation rates will be required for Big Sandy Unit 1 after it is repowered to use natural gas in 2016.

<u>Steam Production Plant</u>

At December 31st, 2013, KPCo's depreciable investment in Steam

Production Plant includes the Big Sandy Generating plant and a 50% undivided interest in Mitchell Generation Plant. The Big Sandy plant is located highway 23 near Louisa, Kentucky and includes two generating units. The Mitchell Plant is located on the Ohio River near Moundsville, West Virginia and also consists of two generating units. All generating units at the Big Sandy and Mitchell plants are currently coal fired.

The generating units and their capacities are as follows (also shown on Schedule IV – Estimated Generation Plant Retirement Dates):

Plant	Unit	Rating	Commercial Operating Date
Big Sandy	1	260 MW	1963
Big Sandy	2	800 MW	1969
Mitchell	1	770 MW	1971
Mitchell	2	790 MW	1971

AEPSC evaluated each of the generating units and determined the following retirement dates for the units:

Plant	Unit	Retirement Date
Big Sandy	2	2015
Big Sandy	1	2016 coal related portion
Big Sandy	1	2031 repowered to use natural gas
Mitchell Plant	1,2	2040

Since KPCo's last depreciation study (property investment dated December 31, 2008), AEP has reevaluated the expected retirement dates for its generation plant including Big Sandy Units 1-2. The reevaluation for these two Big Sandy units indicated that their current estimated retirement dates should be 2015 for Big Sandy Unit 2, 2016 for the coal related portion of Big Sandy Unit 1 and 2031 for Big Sandy Unit 1 after it is repowered to use natural gas. AEP previously estimated individual unit retirement dates of 2023 for Unit 1 and 2029 for Unit 2. According to AEP, the earlier Big Sandy Unit 2 and the coal related portion of Unit 1 retirement dates are because it is not economically feasible to equip the units with necessary environmental controls, not because they have reached the end of their service lives.

Current plans are for the Mitchell Plant to operate for a total life of 69 years or until 2040.

Actuarial Analysis – Transmission, Distribution and General Plant

This method of analyzing past experience represents the application to industrial property of statistical procedures developed in the life insurance field for investigating human mortality. It is distinguished from other methods of life estimation by the requirement that it is necessary to know the age of the property at the time of its retirement and the age of survivors, or plant remaining in service; that is, the installation date must be known for each particular retirement and for each particular survivor.

The application of this method involves the statistical procedure known as the "annual rate method" of analysis. This procedure relates the retirements during each age interval to the exposures at the beginning of that interval, the ratio of these being the annual retirement ratio. Subtracting each retirement ratio from unity yields a sequence of annual survival ratios from which a survivor curve can be determined. This is accomplished by the consecutive multiplication of the survivor ratios. The length of this curve depends primarily upon the age of the oldest property. Normally, if the period of years from the inception of the account to the time of the study is short in relation to the expected maximum life of the property, an incomplete or stub survivor curve results.

While there are a number of acceptable methods of smoothing and extending this stub survivor curve in order to compute the area under it from which the average life is determined, the well-known Iowa Type Curve Method was used in this study.

By this procedure, instead of mathematically smoothing and projecting the stub survivor curve to determine the average life of the group, it was assumed that the stub curve would have the same mortality characteristics as the type curve selected. The selection of the appropriate type curve and average life is accomplished by plotting the stub curve, superimposing on it Iowa curves of the various types and average lives drawn to the same scale, and then determining which Iowa type curve and average life best matches the stub.

The Actuarial Method of Life Analysis was used for the following accounts:

352.0 Transmission Structures & Improvements
353.0 Transmission Station Equipment
361.0 Distribution Structures & Improvements
362.0 Distribution Station Equipment
390.0 General Structures & Improvements

The result of the actuarial analysis for the above accounts is detailed in the depreciation study work papers.

Simulated Plant Record Analysis – Transmission and Distribution Plant

The "Simulated Plant Record" (SPR) method designates a class of statistical techniques that provide an estimate of the age distribution, mortality dispersion and average service life of property accounts whose recorded history provides no indication of the age of the property units when retired from service. For each such account, the available property records usually reveal only the annual gross additions, annual retirements and balances with no indication of the age of either plant retirements or annual plant balances. For this study, the "Balances method" of analysis was used.

The SPR Balances Method is a trial and error procedure that attempts to duplicate the annual balance of a plant account by distributing the actual annual gross additions over time according to an assumed mortality distribution. Specifically, the dollars remaining in service at any date are estimated by multiplying each year's additions by the successive proportion surviving at each age as given by the assumed survivor characteristics. For a given year, the balance indicated is the accumulation of survivors from all vintages and this is compared with the actual book balance. This process is repeated for a different survivor curves and average life combinations until a pattern is discovered which produces a series of "simulated balances" most nearly equaling the actual balances shown in a company's books.

This determination is based on the distribution producing the minimum sum of squared differences between the simulated balance and the actual balances over a test period of years.

The iterative nature of the simulated methods makes them ideally suited for computerized analysis. For each analysis of a given property account, the computer program provides a single page summary containing the results of each analysis indicating the "best fit" based on criteria selected by the user.

The results of my analysis using the Balance Method is shown in the depreciation study work papers. The analysis also shows the value of the Index of Variation of the difference that is calculated according to the the Balances Method where a lower value for the Index of Variation indicates better agreement with the actual data.

The SPR Method of Life Analysis was utilized for the following accounts:

354.0 Transmission Towers & Fixtures
355.0 Transmission Poles & Fixtures
356.0 Transmission Overhead Conductor & Devices
364.0 Distribution Poles, Towers & Fixtures
365.0 Distribution OH Conductor & Devices
366.0 Distribution Underground Conduit
367.0 Distribution Underground Conductor & Devices
368.0 Distribution Line Transformers
369.0 Distribution Services
370.0 Distribution Meters

371.0 Installation on Customers Premises

373.0 Street Lighting & Signal Systems

Vintage Year Accounting – General Equipment

In 1998, the Company began using a vintage year accounting method for general plant accounts 391 to 398 in accordance with Federal Energy Regulatory Commission Accounting Release Number 15 (AR-15). This accounting method requires the amortization of vintage groups of property over their useful lives. AR-15 also requires that property be retired when it meets its average service life.

As a result, my recommendation for these accounts is that the current useful life approved by the Commission be retained and used to continue amortization of the account balances.

4. Final Selection of Average Life and Curve Type

The final selection of average life and curve type for each depreciable plant account analyzed by the Actuarial and SPR Methods was primarily based on the results of the mortality analyses of past retirement history.

III. NET SALVAGE

1. Net Salvage - Steam Production Plant

The net salvage analysis for steam production plant included a review of the plant's experienced functional interim retirement, salvage and removal history for the period 2001-2013. No interim retirements were estimated for Big Sandy Plant in this depreciation study since Unit 2 is estimated to retire in 2015, the coal related portions of Unit 1 are estimated to retire in 2016 and the repowered Unit 1 (to use natural gas) is expected to retire in 2031.

While a standard type of analysis was used by the depreciation study to determine the net salvage characteristics applicable to interim retirements for the plants, the most significant net salvage amounts for generating plants occurs at the end of their life. Therefore, to assist in establishing total net salvage applicable to Big Sandy and Mitchell plants, the Company contracted with Sargent & Lundy (S&L) to prepare conceptual demolition cost estimates. The S&L cost estimates to demolish the plants are based on current (2013) price levels which were inflated to retirement dates in the depreciation study. These estimates were incorporated into the calculation of a net salvage ratio for Steam Production Plant. S&L's demolition costs do not include Asset Retirement Obligation (ARO) amounts associated with the removal of asbestos or any cost associated with the final disposition of Big Sandy or Mitchell Plant landfills and ash ponds. The costs to remove asbestos and cover ash ponds are included separately in the cost of service through the accounting for asset retirement obligations.

2. Net Salvage – Transmission, Distribution and General Plant

The net salvage percentages used in this report for Transmission, Distribution and General Plant are expressed as percent of original cost and are based on the Company's experience combined with the judgment of the analyst. KPCo maintains salvage and removal costs in its depreciation ledger at the functional plant level, rather than by primary plant accounts. To determine gross salvage, gross removal and net salvage percentages for individual plant accounts, original cost retirements, salvage and removal were taken from the Company's account history in its PowerPlant software which detailed these amounts by account for the period 2000 to 2013. Gross salvage and cost of removal percentages were calculated using the data from this fourteen year time period for each account. The salvage and removal percentages for each account were then netted to determine a net salvage percentage for each account.

The net salvage percents were converted to net salvage ratios (1 minus the net salvage percentage) and appear in Column IV on Schedule I and were used to determine the total amount to be recovered through depreciation. The same net salvage was also reflected in the determination of the calculated depreciation requirement, which was used to allocate accumulated depreciation at the functional group to the accounts comprising each group.

5. <u>Net Salvage – Ratios</u>

The net salvage ratios shown on Schedule I of this report may be explained as follows:

a. Where the ratio is shown as unity (1.00), it was assumed that the net salvage in that particular account would be zero.

b. Where the ratio is less than unity, it was assumed that the salvage exceeded the removal costs. For example, if the net salvage were 20%, the net salvage ratio would be expressed as .80.

c. Where the ratio is greater than unity, it was assumed that the salvage was less than the cost of removal. For example, if the net salvage were minus 5%, the net salvage ratio would be expressed as 1.05.

IV. CALCULATION OF DEPRECIATION REQUIREMENT AT DECEMBER 31, 2013

The accumulated depreciation by functional group was allocated to individual plant accounts based on the calculation of a depreciation requirement (theoretical reserve) for each plant account using the average service life, curve type and net salvage amount recommended in this study.

V. STUDY RESULTS

Production, Transmission, Distribution and General plant results are discussed below. In addition, Transmission, Distribution and General Plant average service life, retirement dispersion pattern and net salvage percentages used to calculate each primary plant account depreciation rate are shown on Schedule III where the mortality characteristics and net salvage values for the current rates are also shown. The changes to the mortality characteristics follow trends shown by historical retirement experience. Gross salvage and gross cost of removal percentages were largely based on the history of each account for the period 2000-2013.

Steam Production Plant

Depreciation rates for Mitchell Plant were calculated by plant account with the expectation that the total cost including net salvage would be recovered by 2040 which is the estimated retirement date for Mitchell Plant. New depreciation rates for Big Sandy Plant were not recommended by the depreciation study. The comparison of steam production depreciation accruals on Schedule II using the currently approved depreciation rates and the study depreciation rates includes

Mitchell Plant. The original cost and accumulated depreciation amounts used for Mitchell Plant are 50% of the plant's original cost and accumulated depreciation on KPCo's books at December 31, 2013.

The decrease in steam production depreciation expense due to a change in depreciation rates was primarily due to the longer life estimate for Mitchell Plant in this proceeding (2040 retirement date) versus a previously estimated 2031 retirement date. The depreciation study doesn't recommend any changes to the Big Sandy Plant's depreciation rates.

Terminal demolition costs are included in the steam production depreciation rates. The estimates of demolition costs were developed by Sargent & Lundy. S&L estimated demolition cost in 2013 dollars for Big Sandy Plant and Mitchell Plant (KPCo's 50% share) was $28,831,786 and $21,185,697, respectively.

Transmission Plant

The depreciation rates for Transmission plant increased from 1.71% to 2.66% due to increases in the net salvage ratio for five accounts (accounts 352, 353, 354, 355 and 356) and decreases in the average service life for two accounts (accounts 354, and 355). The increase was partially offset by an increase in the average service life for account 352.

Distribution Plant

The depreciation rates for Distribution plant increased from 3.52% to 4.48% due to increases in the net salvage ratio for nine accounts (accounts 361, 362, 364, 365, 367, 368, 369, 371 and 373) and a decrease in the average service life for one account (account 370). The increase was partially offset by a decrease in the net salvage ratio for account 370 and by increases in the average service life for five accounts (accounts 361, 362, 366, 369 and 373).

General Plant

The depreciation rates for General plant increased from 2.54% to 4.42% due to increases in the net salvage ratio for three accounts (accounts 391, 394 and 398) and a reduction in the average service life for account 390. The increase was partially offset by a decrease in the net salvage ratio for account 397.

SCHEDULE I – EXPLANATION OF COLUMN HEADINGS

Schedule I shows the determination of the recommended annual depreciation accrual rate by primary plant accounts by the straight line remaining life method. An explanation of the schedule follows:

Column I	-	Account number.
Column II	-	Account title.
Column III	-	Original Cost at December 31, 2013
Column IV	-	Net Salvage Ratio.
Column V	-	Total to be Recovered (Column III) * (Column IV).
Column VI	-	Calculated Depreciation Requirement.
Column VII	-	Allocated Accumulated Depreciation – accumulated depreciation (book reserve) spread to each account on the basis of the Calculated Depreciation Requirement shown in Column VI.
Column VIII	-	Remaining to be Recovered (Column V - Column VII).
Column IX	-	Average Remaining Life.
Column X	-	Recommended Annual Accrual Amount.
Column XI	-	Recommended Annual Accrual Percent or Depreciation Rate (Column X/Column III).

KENTUCKY POWER COMPANY
SCHEDULE I - CALCULATION OF DEPRECIATION RATES BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2013
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

									Annual Accrual	
Acct. No.	Account Title	Original Cost	Net Salvg. Ratio	Total to be Recovered	Calculated Depreciation Requirement	Accumulated Depreciation	Remaining to Be Recovered	Avg. Remain Life	Amount	Percent
(I)	(II)	(III)	(IV)	(V)	(VI)	(VII)	(VIII)	(IX)	(X)	(XI)
STEAM PRODUCTION PLANT										
Big Sandy Plant (1)										
311	Structures & Improvements	43,291,665	**(1)**	**(1)**	**(1)**	30,726,379	**(1)**	**(1)**	1,636,425	3.78%
312	Boiler Plant Equipment	362,456,070	**(1)**	**(1)**	**(1)**	177,325,748	**(1)**	**(1)**	13,700,839	3.78%
312	Boiler Plant Equip SCR Catalyst **(2)**	8,147,622	**(1)**	**(1)**	**(1)**	5,742,300	**(1)**	**(1)**	389,456	4.78%
314	Turbogenerator Units	109,522,949	**(1)**	**(1)**	**(1)**	61,149,688	**(1)**	**(1)**	4,139,967	3.78%
315	Accessory Electrical Equip.	16,513,202	**(1)**	**(1)**	**(1)**	12,896,303	**(1)**	**(1)**	624,199	3.78%
316	Misc. Power Plant Equip.	8,709,178	**(1)**	**(1)**	**(1)**	5,351,493	**(1)**	**(1)**	329,207	3.78%
	Total	548,640,686				293,191,911			20,820,093	3.79%
Mitchell Plant (3)										
311	Structures & Improvements	42,000,197	1.07	44,940,211	18,282,178	16,183,402	28,756,809	25.01	1,149,812	2.74%
312	Boiler Plant Equipment	765,644,984	1.07	819,240,133	245,324,500	238,518,432	580,721,701	24.25	23,947,287	3.13%
312	Boiler Plant Equip SCR Catalyst **(2)**	8,190,115	1.00	8,190,115	4,023,394	2,378,493	5,811,622	4.07	1,023,764	12.50%
314	Turbogenerator Units	53,295,697	1.07	57,026,396	29,106,660	33,613,523	23,412,873	23.84	982,084	1.84%
315	Accessory Electrical Equip.	17,080,672	1.07	18,276,319	9,466,086	11,043,285	7,233,034	25.81	280,242	1.64%
316	Misc. Power Plant Equip.	7,693,412	1.07	8,231,951	3,289,590	3,072,520	5,159,431	23.96	215,335	2.80%
	Total	893,905,077	1.07	955,905,125	309,492,408	304,809,655	651,095,470	23.59	27,598,524	3.09%
	Total Steam Prod. Plant	**1,442,545,763**	**0.66**	**955,905,125**	**309,492,408**	**598,001,566**	**651,095,470**	**13.45**	**48,418,617**	**3.36%**
TRANSMISSION PLANT										
350.1	Land Rights	26,456,147	1.00	26,456,147	8,498,622	7,016,166	19,439,981	50.91	381,850	1.44%
352	Structures & Improvements	6,636,668	1.10	7,300,335	3,172,075	2,618,754	4,681,581	33.93	137,978	2.08%
353	Station Equipment	170,843,671	1.03	175,968,981	34,476,675	28,462,741	147,506,240	40.20	3,669,309	2.15%
354	Towers & Fixtures	94,517,543	1.10	103,969,297	56,679,229	46,792,396	57,176,901	23.20	2,464,522	2.61%
355	Poles & Fixtures	74,696,720	1.61	120,261,719	28,658,583	23,659,527	96,602,192	32.75	2,949,685	3.95%
356	OH Conductor & Devices	122,537,908	1.27	155,623,143	70,585,347	58,272,803	97,350,340	27.32	3,563,336	2.91%
357	Undergrnd Conduit	11,590	1.00	11,590	4,345	3,587	8,003	23.13	346	2.99%
358	Undergrnd Conductor	106,066	1.00	106,066	49,568	40,922	65,144	23.44	2,779	2.62%
	Total Transmission Plant	495,806,313	**1.19**	589,697,279	202,124,444	166,866,896	422,830,383	32.11	13,169,805	2.66%
DISTRIBUTION PLANT										
360.1	Land Rights	5,343,520	1.00	5,343,520	1,411,791	1,371,633	3,971,887	55.18	71,981	1.35%
361	Structures & Improvements	4,372,006	1.12	4,896,647	1,354,850	1,316,312	3,580,335	50.63	70,716	1.62%
362	Station Equipment	83,664,562	1.07	89,521,081	18,549,279	18,021,648	71,499,433	26.16	2,733,159	3.27%
364	Poles, Towers, & Fixtures	180,551,331	1.30	234,716,730	68,606,654	66,655,150	168,061,580	19.82	8,479,394	4.70%
365	OH Conductor & Devices	179,538,721	0.94	168,766,398	33,083,601	32,142,543	136,623,855	20.90	6,537,027	3.64%
366	Underground Conduit	6,377,091	1.00	6,377,091	1,464,955	1,423,285	4,953,806	34.66	142,926	2.24%
367	Underground Conductor	9,812,956	1.13	11,088,640	1,655,544	1,608,452	9,480,188	37.43	253,278	2.58%
368	Line Transformers	119,012,919	1.01	120,203,048	28,150,578	27,349,840	92,853,208	19.15	4,848,731	4.07%
369	Services	53,900,363	1.38	74,382,501	17,054,558	16,569,444	57,813,057	15.41	3,751,658	6.96%
370	Meters	24,723,287	0.97	23,981,588	10,273,269	9,981,048	14,000,540	9.72	1,440,385	5.83%
371	Installations on Custs. Prem.	20,056,550	1.32	26,474,646	7,344,863	7,135,939	19,338,707	7.95	2,432,542	12.13%
373	Street Lighting & Signal Sys.	3,349,341	1.24	4,153,183	1,231,600	1,196,567	2,956,616	14.07	210,136	6.27%
	Total Distribution Plant	690,702,647	**1.11**	769,905,074	190,181,542	184,771,861	585,133,213	18.89	30,971,931	4.48%

KENTUCKY POWER COMPANY
SCHEDULE I - CALCULATION OF DEPRECIATION RATES BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2013
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

Acct. No.	Account Title	Original Cost	Net Salvg. Ratio	Total to be Recovered	Calculated Depreciation Requirement	Accumulated Depreciation	Remaining to Be Recovered	Avg. Remain Life	Annual Accrual Amount	Annual Accrual Percent
(I)	(II)	(III)	(IV)	(V)	(VI)	(VII)	(VIII)	(IX)	(X)	(XI)
GENERAL PLANT										
389.1	Land Rights	37,384	1.00	37,384	11,898	6,909	30,475	51.13	596	1.59%
390	Structures & Improvements	19,811,669	1.00	19,811,669	9,535,669	5,537,254	14,274,415	18.15	786,469	3.97%
391	Office Furniture & Equipment	1,683,333	1.00	1,683,333	377,310	219,100	1,464,233	27.15	53,931	3.20%
392	Transportation Equipment	14,768	1.00	14,768	1,742	1,012	13,756	26.46	520	3.52%
393	Stores Equipment	164,548	1.00	164,548	60,496	35,129	129,419	18.97	6,822	4.15%
394	Tools Shop & Garage Equip.	3,553,696	1.09	3,873,529	1,042,908	605,604	3,267,925	21.92	149,084	4.20%
395	Laboratory Equipment	141,765	1.00	141,765	89,929	52,221	89,544	10.97	8,163	5.76%
396	Power Operated Equipment	5,931	1.00	5,931	2,728	1,584	4,347	13.50	322	5.43%
397	Communication Equipment	7,318,955	0.97	7,099,386	2,872,871	1,668,243	5,431,143	13.10	414,591	5.66%
398	Miscellaneous Equipment	1,065,616	1.03	1,097,584	464,407	269,676	827,908	11.54	71,743	6.73%
	Total General Plant	33,797,665	**1.00**	33,929,897	14,459,958	8,396,732	25,533,165	17.11	1,492,241	4.42%
	Total Depreciable Plant	2,662,852,388		2,349,437,375	716,258,352	958,037,055	1,684,592,231		94,052,594	3.53%

N/A = Not Applicable

Notes:

(1) The Company plans to retire Big Sandy Unit 2 at the end of May 2015 and the coal related portions of Unit 1 in 2016. Since the Commission authorized (Case No. 2012-00578) the Company to recover the coal-related portion of Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2 and any other site related retirement costs, this depreciation recommends that the existing approved depreciation rates for Big Sandy Plant be retained until a future proceeding that includes the remaining portion of Big Sandy Unit 1 and the cost to re-power this unit to use natural gas.

(2) An annualized depreciation rate for Big Sandy Plant's SCR Catalyst was calculated using currently approved rates and included in the above analysis. A separate depreciation rate was calculated for Mitchell Plant's SCR Catalyst using AEP Air Emmissions Control estimated average life for the catalyst.

(3) Mitchell Plant cost at December 31, 2013. At December 31, 2013 the Mitchell Plant was jointly owned 50% by Kentucky Power Company and 50% by AEP Generating Resources and therefore the cost shown above is 50% of the total Mitchell Plant depreciable plant in service. The Mitchell Plant cost includes 50% of the investment in the gypsum plant underloader located at the Mountaineer Generating Station.

KENTUCKY POWER COMPANY
SCHEDULE II - COMPARE DEPRECIATION EXPENSE USING CURRENT AND STUDY RATES
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2013

ACCT. NO. (1)	ACCOUNT TITLE (2)	ORIGINAL COST (3)	CURRENT APPROVED RATE (4)	ANNUAL ACCRUAL (5)	STUDY RATE (6)	STUDY ACCRUAL (7)	DIFFERENCE (DECREASE) (8)
STEAM PRODUCTION PLANT							
BIG SANDY PLANT (a)							
311	Structures & Improvements	43,291,665	3.78%	1,636,425	3.78%	1,636,425	0
312	Boiler Plant Equipment	362,456,070	3.78%	13,700,839	3.78%	13,700,839	0
312	Boiler Plant Equip SCR Catalyst	8,147,622	4.78%	389,456	4.78%	389,456	0
314	Turbogenerator Units	109,522,949	3.78%	4,139,967	3.78%	4,139,967	0
315	Accessory Electrical Equipment	16,513,202	3.78%	624,199	3.78%	624,199	0
316	Misc. Power Plant Equip.	8,709,178	3.78%	329,207	3.78%	329,207	0
	Total	548,640,686	3.79%	20,820,093	3.79%	20,820,093	0
MITCHELL PLANT - (b)							
311	Structures & Improvements	42,000,197	2.87%	1,205,406	2.74%	1,149,812	(55,594)
312	Boiler Plant Equipment	765,644,984	3.90%	29,860,154	3.13%	23,947,287	(5,912,867)
312	Boiler Plant Equip SCR Catalyst **(c)**	8,190,115	10.00%	819,012	12.50%	1,023,764	204,752
314	Turbogenerator Units	53,295,697	2.86%	1,524,257	1.84%	982,084	(542,173)
315	Accessory Electrical Equipment	17,080,672	2.39%	408,228	1.64%	280,242	(127,986)
316	Misc. Power Plant Equip.	7,693,412	2.79%	214,646	2.80%	215,335	689
	Total	893,905,077	3.81%	34,031,703	3.09%	27,598,524	(6,433,179)
	Total Steam Production Plant	**1,442,545,763**	**3.80%**	**54,851,796**	**3.36%**	**48,418,617**	**(6,433,179)**
TRANSMISSION PLANT							
350.1	Land Rights	26,456,147	1.71%	452,400	1.44%	381,850	(70,550)
352	Structures & Improvements	6,636,668	1.71%	113,487	2.08%	137,978	24,491
353	Station Equipment	170,843,671	1.71%	2,921,427	2.15%	3,669,309	747,882
354	Towers & Fixtures	94,517,543	1.71%	1,616,250	2.61%	2,464,522	848,272
355	Poles & Fixtures	74,696,720	1.71%	1,277,314	3.95%	2,949,685	1,672,371
356	OH Conductor & Devices	122,537,908	1.71%	2,095,398	2.91%	3,563,336	1,467,938
357	Underground Conduit	11,590	1.71%	198	2.99%	346	148
358	Underground Conductor & Devices	106,066	1.71%	1,814	2.62%	2,779	965
	Total Transmission Plant	**495,806,313**	**1.71%**	**8,478,288**	**2.66%**	**13,169,805**	**4,691,517**
DISTRIBUTION PLANT							
360.1	Land Rights	5,343,520	3.52%	188,092	1.35%	71,981	(116,111)
361	Structures & Improvements	4,372,006	3.52%	153,895	1.62%	70,716	(83,179)
362	Station Equipment	83,664,562	3.52%	2,944,993	3.27%	2,733,159	(211,834)
364	Poles, Towers, & Fixtures	180,551,331	3.52%	6,355,407	4.70%	8,479,394	2,123,987
365	Overhead Conductor & Devices	179,538,721	3.52%	6,319,763	3.64%	6,537,027	217,264
366	Underground Conduit	6,377,091	3.52%	224,474	2.24%	142,926	(81,548)
367	Underground Conductor	9,812,956	3.52%	345,416	2.58%	253,278	(92,138)
368	Line Transformers	119,012,919	3.52%	4,189,255	4.07%	4,848,731	659,476
369	Services	53,900,363	3.52%	1,897,293	6.96%	3,751,658	1,854,365
370	Meters	24,723,287	3.52%	870,260	5.83%	1,440,385	570,125
371	Installations on Custs. Prem.	20,056,550	3.52%	705,991	12.13%	2,432,542	1,726,551
373	Street Lighting & Signal Sys.	3,349,341	3.52%	117,897	6.27%	210,136	92,239
	Total Distribution Plant	**690,702,647**	**3.52%**	**24,312,736**	**4.48%**	**30,971,933**	**6,659,197**

KENTUCKY POWER COMPANY
SCHEDULE II - COMPARE DEPRECIATION EXPENSE USING CURRENT AND STUDY RATES
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2013

ACCT. NO. (1)	ACCOUNT TITLE (2)	ORIGINAL COST (3)	CURRENT APPROVED RATE (4)	ANNUAL ACCRUAL (5)	STUDY RATE (6)	STUDY ACCRUAL (7)	DIFFERENCE (DECREASE) (8)
GENERAL PLANT							
389.1	Land Rights	37,384	2.54%	950	1.59%	596	(354)
390	Structures & Improvements	19,811,669	2.54%	503,216	3.97%	786,469	283,253
391	Office Furniture & Equipment	1,683,333	2.54%	42,757	3.20%	53,931	11,174
392	Transportation Equipment	14,768	2.54%	375	3.52%	520	145
393	Stores Equipment	164,548	2.54%	4,180	4.15%	6,822	2,642
394	Tools Shop & Garage Equipment	3,553,696	2.54%	90,264	4.20%	149,084	58,820
395	Laboratory Equipment	141,765	2.54%	3,601	5.76%	8,163	4,562
396	Power Operated Equipment	5,931	2.54%	151	5.43%	322	171
397	Communication Equipment	7,318,955	2.54%	185,901	5.66%	414,591	228,690
398	Miscellaneous Equipment	1,065,616	2.54%	27,067	6.73%	71,743	44,676
	Total General Plant	**33,797,665**	**2.54%**	**858,462**	**4.42%**	**1,492,241**	**633,779**
	Total Depreciable Plant	**2,662,852,388**	**3.32%**	**88,501,282**	**3.53%**	**94,052,596**	**5,551,314**

Notes:

(a) The depreciation study recommends that the current approved depreciation rates for Big Sandy Plant remain in effect until the next base case which will reflect the retirement of Big Sandy Unit 2 in 2015, the coal related portions of Unit 1 in 2016 and the cost to re-power Unit 1 to burn natural gas. Therefore there is no change in depreciation expense due to a change in depreciation rates for Big Sandy Plant.

(b) The current approved rates for Mitchell Generating Plant are from AEP affiliated company, Ohio Power Company as per the Order in Case No. 2012-00578.

(c) The depreciation rate was revised for the SCR catalyst at Mitchell Generating Station using AEP Generation's estimated average life for the catalyst of 8 years.

KENTUCKY POWER COMPANY
SCHEDULE III - COMPARISON OF MORTALITY CHARACTERISTICS
DEPRECIATION STUDY AS OF DECEMBER 31, 2013

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
		Existing Rates (See note, below)					Current Study Rates				
		Average Service Life (Years)	Iowa Curve	Salvage Factor	Cost of Removal Factor	Net Salvage Factor	Average Service Life (Years)	Iowa Curve	Salvage Factor	Cost of Removal Factor	Net Salvage Factor
TRANSMISSION PLANT											
350.1	Rights of Way	75	R4.0	N/A	N/A	0%	75	R4.0	0%	0%	0%
352.0	Structures & Improvements	55	S1.5	N/A	N/A	0%	60	S3.0	0%	10%	-10%
353.0	Station Equipment	50	R0.5	N/A	N/A	25%	50	L0.5	8%	11%	-3%
354.0	Towers & Fixtures	55	R4.0	N/A	N/A	0%	51	S6.0	3%	13%	-10%
355.0	Poles & Fixtures	45	R3.0	N/A	N/A	0%	43	L3.0	2%	63%	-61%
356.0	Overhead Conductor & Devices	50	R3.0	N/A	N/A	10%	50	S6.0	6%	33%	-27%
357.0	Underground Conduit	37	R2.0	N/A	N/A	0%	37	R2.0	0%	0%	0%
358.0	Underground Conductor and Devices	44	R1.0	N/A	N/A	0%	44	R1.0	0%	0%	0%
DISTRIBUTION PLANT											
360.1	Rights of Way	75	R4.0	N/A	N/A	0%	75	R4.0	0%	0%	0%
361.0	Structures & Improvements	65	L0.5	N/A	N/A	0%	70	R2.0	4%	16%	-12%
362.0	Station Equipment	25	L0.0	N/A	N/A	25%	33	R0.5	10%	17%	-7%
364.0	Poles, Towers, & Fixtures	28	L0.0	N/A	N/A	25%	28	R0.5	18%	48%	-30%
365.0	Overhead Conductor & Devices	26	R1.5	N/A	N/A	25%	26	L0.0	30%	24%	6%
366.0	Underground Conduit	37	R2.0	N/A	N/A	0%	45	R3.0	0%	0%	0%
367.0	Underground Conductor	44	R1.0	N/A	N/A	0%	44	R0.5	1%	14%	-13%
368.0	Line Transformers	25	R1.5	N/A	N/A	15%	25	L0.0	29%	30%	-1%
369.0	Services	18	R2.0	N/A	N/A	0%	20	L0.0	1%	39%	-38%
370.0	Meters	27	R0.5	N/A	N/A	0%	17	R4.0	22%	19%	3%
371.0	Installations on Custs. Prem.	11	L0.0	N/A	N/A	30%	11	L0.0	1%	33%	-32%
373.0	Street Lighting & Signal Sys.	15	L0.0	N/A	N/A	15%	20	L0.0	1%	25%	-24%
GENERAL PLANT											
389.1	Rights of Way	75	R4.0	N/A	N/A	0%	75	R4.0	0%	0%	0%
390.0	Structures & Improvements	45	L3.0	N/A	N/A	0%	35	L2.0	1%	1%	0%
391.0	Office Furniture & Equipment	35	R0.5	N/A	N/A	10%	35	SQ	0%	0%	0%
392.0	Transportation Equipment	30	R3.0	N/A	N/A	0%	30	SQ	0%	0%	0%
393.0	Stores Equipment	30	R1.0	N/A	N/A	0%	30	SQ	0%	0%	0%
394.0	Tools Shop & Garage Equipment	30	R0.5	N/A	N/A	0%	30	SQ	0%	9%	-9%
395.0	Laboratory Equipment	30	L5.0	N/A	N/A	0%	30	SQ	0%	0%	0%
396.0	Power Operated Equipment	N/A	N/A	N/A	N/A	N/A	25	SQ	0%	0%	0%
397.0	Communication Equipment	22	L3.0	N/A	N/A	0%	22	SQ	6%	3%	3%
398.0	Miscellaneous Equipment	20	S5.0	N/A	N/A	0%	20	SQ	0%	3%	-3%

Note: Kentucky Power Company's existing depreciation rates are from Case No. 91-066. No detail of Cost of Removal % and Salvage Factor % is available from the order from that Case.

APPALACHIAN POWER COMPANY AND

WHEELING POWER COMPANY

DEPRECIATION STUDY REPORT OF

ELECTRIC PLANT IN SERVICE

AT DECEMBER 31, 2017

DEPRECIATION STUDY REPORT

Table of Contents

I. INTRODUCTION

This report presents the results of a depreciation study of Appalachian Power Company's (APCo) and Wheeling Power Company's (WPCo) depreciable electric utility plant in service at December 31, 2017. The study was prepared by Jason A. Cash, Staff Accountant – Accounting Policy and Research at American Electric Power Service Corporation (AEPSC). The purpose of the depreciation study was to develop appropriate annual depreciation accrual rates for each of the primary plant accounts that comprise the functional groups for which APCo and WPCo compute their annual depreciation expense.

The proposed depreciation rates are based on the Average Remaining Life Method of computing depreciation. Further explanation of this method is contained in Section II of this report.

The definition of depreciation used in the study is the same as that used by the Federal Energy Regulatory Commission (FERC) and the National Association of Regulatory Utility Commissioners:

> "Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities."
>
> "Service value means the difference between original cost and the

net salvage value (net salvage value means the salvage value of the property retired less the cost of removal) of the electric plant." (FERC Accounting and Reporting Requirements for Public Utilities and Licensees, ¶15.001.)

APCO Depreciation Rates

Schedule I of this report provides the proposed depreciation accrual rates by primary plant accounts and functional plant classifications. Schedule II compares depreciation expense to rates approved by the Commission and rates proposed in the depreciation study. Schedule III compares the Transmission, Distribution and General Plant mortality characteristics that were used to compute the existing and proposed depreciation rates and accruals. Schedule IV provides the estimated generation plant retirement dates used to calculate depreciation rates.

A comparison of APCo's current functional group composite depreciation rates and accruals to the proposed functional group rates and accruals are provided below in Table 1 (see Schedule I for detail by plant account):

Table 1 - Depreciation Rates and Accruals
Appalachian Power Company
Based on Plant In Service at December 31, 2017
(Total Company)

	Existing		Study		
Functional Plant Group	Rates	Accruals	Rates	Accruals	Difference
Steam Production	2.93%	158,217,503	3.68%	198,646,937	40,429,434
Hydraulic Production	2.81%	7,024,127	3.73%	9,310,257	2,286,130
Other Production	2.42%	15,152,177	2.58%	16,203,244	1,051,067
Transmission	1.69%	48,581,827	2.11%	60,683,210	12,101,383
Distribution	3.82%	140,897,820	4.10%	151,333,997	10,436,177

General	2.37%	5,027,180	2.74%	5,811,299	784,119
Total Depreciable Plant	**2.87%**	**374,900,634**	**3.39%**	**441,988,944**	**67,088,310**

Based on total Company Depreciable Plant In-Service as of December 31, 2017, the Company is proposing an increase in depreciation rates that would produce an annual increase in depreciation expense of $67,088,310 when applying the West Virginia depreciation rates to the total Company depreciable plant in service balances. The depreciation rate changes are necessary because of changes in investment, average service lives and net salvage estimates used to calculate APCo's current depreciation rates.

WPCo Depreciation Rates

Schedule V of this report provides the proposed depreciation accrual rates by primary plant accounts and functional plant classifications. Schedule VI compares depreciation expense to rates approved by the Commission and rates proposed by the depreciation study for production, transmission, distribution, and general plant. Schedule VII compares the Transmission, Distribution and General Plant mortality characteristics that were used to compute the proposed depreciation rates and accruals and the mortality characteristics used to determine the existing depreciation rates and accruals. Schedule VIII provides the estimated retirement date for the Mitchell Plant that was used to calculate depreciation rates.

A comparison of WPCo's current functional group composite depreciation rates and accruals to the proposed functional group rates and accruals are provided below in Table 2 (see Schedule V for detail by plant account):

Table 2 - Depreciation Rates and Accruals
Wheeling Power Company
Based on Plant In Service at December 31, 2017

	Existing		Study		
Functional Plant Group	Rates	Accruals	Rates	Accruals	Difference
Steam Production	2.79%	28,050,565	3.13%	31,506,398	3,455,833
Transmission	1.84%	2,573,599	2.16%	3,026,571	452,972
Distribution	3.75%	6,673,564	3.88%	6,895,288	221,724
General	1.45%	77,778	2.23%	119,460	41,682
Total Depreciable Plant	**2.81%**	**37,375,506**	**3.13%**	**41,547,717**	**4,172,211**

Based on total Company Depreciable Plant In-Service as of December 31, 2017, the Company is proposing an increase in depreciation rates that would produce an annual increase in depreciation expense of $4,172,211 when applying the West Virginia depreciation rates to the total Company depreciable plant in service balances. The depreciation rate changes are necessary because of changes in investment, average service lives and net salvage estimates used to calculate WPCo's current depreciation rates.

II. DISCUSSION OF METHODS AND PROCEDURES USED IN THE STUDY

1. Group Method

All of the depreciable property included in this report was considered on a group plan. Under the group plan, depreciation expense is accrued upon the basis of the original cost of all property included in each depreciable plant account. Upon retirement of any depreciable property, its full cost, less any net salvage realized, is charged to the accrued depreciation reserve regardless of the age of the particular item retired. Also, under this plan, the dollars in each primary plant account are considered as a separate group for depreciation accounting purposes and an annual depreciation rate for each account is determined. The annual accruals by primary account were then summed, to arrive at the total accrual for each functional group. The total accrual divided by the original cost yields the functional group accrual rate.

2. Determination of Annual Depreciation Rates by the Average Remaining Life Method

APCo's and WPCo's current depreciation rates are based on the Average Remaining Life Method. The Average Remaining Life Method recovers the original cost of the plant, adjusted for net salvage, less accumulated depreciation, over the average remaining life of the plant. By this method, the annual depreciation rate for each account is determined on the following basis:

$$\text{Annual Depreciation Expense} = \frac{(\text{Orig. Cost})\ (\text{Net Salvage Ratio}) - \text{Accumulated Depreciation}}{\text{Average Remaining Life}}$$

$$\text{Annual Depreciation Rate} = \frac{\text{Annual Depreciation Expense}}{\text{Original Cost}}$$

3. Methods of Life Analysis

Depending upon the type of property and the nature of the data available from the property accounting records, one of three life analyses was used to arrive at the historically realized mortality characteristics and service lives of the depreciable plant investments. These methods are identified and described as follows:

Life Span Analysis

The life span analysis was employed for Production Plant. This includes APCo's investment in steam, hydraulic and other generating plants and WPCo's 50% interest in Mitchell plant. The life-span method of analysis is particularly suited to specific location property, such as a generating plant, where all of the surviving investments are likely to be retired in total at a future date.

The key elements in the life span analysis are the age of the surviving investments, the projected retirement date of the facility and the expected interim retirements. Interim retirements are those that are expected to occur between the date of the depreciation study and the expected final retirement date of the generating plant. Examples of interim retirements include fans, pumps, motors, a set of boiler tubes, a turbine rotor, etc. The interim retirement history for each primary production plant account was analyzed and the results of those analyses were used to project future interim retirements.

The age of the surviving investments was obtained from the applicable property accounting records. Ms. Debra Osborne, Vice President Generation Assets APCo/Kentucky, provided the estimated retirement dates used in the life-span analysis for Steam Production Plant, Hydraulic Production Plant and Other Production Plant. A discussion of the life analyses for Steam Production, Hydraulic Production and Other Production Plants follows.

Steam Production Plant

APCo's depreciable investments in Steam Production Plant are the Amos, Clinch River, and Mountaineer plants. The Amos plant is located in Winfield, West Virginia and includes three units. The Clinch River plant is located near Cleveland, Virginia and has two units that are currently operating (units 1 and 2).

The Mountaineer plant is located in New Haven, West Virginia and has one unit. The Amos and Mountaineer plants are coal fired. APCo converted Clinch River Units 1 and 2 from coal fired units to natural gas fired units in 2016. The generating units, capacities, fuel type and estimated retirement dates are shown on Schedule IV – Estimated Generation Plant Retirement Dates.

The proposed expected retirement dates used in this depreciation study for APCo's steam generation plants are the same retirement dates that were proposed by the Company in the depreciation study filed with Case No. 14-1151-E-D which used plant in service balances at December 31, 2013. The retirement dates are shown below on Table 3 (and also on Schedule IV):

Table 3 - Estimated Steam Plant Retirement Dates

Plant	Capacity (MW)	Year Installed	Year Retired	Life Span (Years)
Steam Production Plant				
Mountaineer				
Unit 1	1,300	1980	2040	60
Amos				
Unit 1	800	1971	2040	69
Unit 2	800	1972	2040	68
Unit 3	1,300	1973	2040	67
Clinch River				
Unit 1	235	1958	2025	67
Unit 2	235	1958	2025	67

Note that in its order in Case No. 14-1151-E-D, the Commission accepted the staff's proposed depreciation rates which used a 2040 retirement date for Amos, Mountaineer and Clinch River Units 1 and 2. APCo proposed a 2025 retirement date for Clinch River Units 1 and 2 in Case No. 14-1151-E-D and also proposes depreciation rates using a 2025 retirement date in this case.

Depreciation rates for Amos, Clinch River, and Mountaineer plants are calculated by plant account.

WPCo's depreciable investment in Steam Production Plant is a 50% interest in Mitchell plant. Mitchell plant is located near Moundsville, WV and has two units. Kentucky Power Company (KPCo) has the remaining 50% interest in the plant and is also the plant's operator. Mitchell plant is coal fired with an estimated retirement year of 2040 (also shown on Schedule VIII).

Hydraulic Production Plant

APCo's investment in Hydraulic Production plant consists of the Buck, Byllesby, Claytor, Leesville, London, Marmet, Niagara, Smith Mountain and Winfield plants. In April 2017, APCo sold the Reusens Hydro facility to Eagle Creek Renewable Energy, LLC. The sale resulted in a gain for APCo. The gain (credit) on the sale was included by the current depreciation study in the Smith Mountain Hydro Plant's accumulated depreciation balance which reduced the depreciation rates and the amount remaining to be recovered for Smith Mountain.

APCo's Hydro plants consist of a number of generating units that have been placed into commercial operation over the period from 1906 through 1965. Except for the sale of Reusens Hydro, noted above, there was no change in the estimated retirement year for the hydraulic plants in the current depreciation study versus the prior depreciation study which used plant in service balances at December 31, 2013. The hydraulic plants, capacities, estimated year to be retired and life span are shown on Table 4 below (and also on Schedule IV):

Table 4 - Estimated Hydraulic Plant Retirement Dates

Plant	Capacity (MW)	Year Installed	Year Retired	Life Span (Years)
Hydraulic Production Plant				
Buck	8.5	1912	2024	112
Byllesby	21.6	1912	2024	112
Claytor	75.0	1939	2041	102
Niagara	2.4	1906	2024	118
Leesville	50.0	1964	2040	76
London	14.4	1935	2044	109
Marmet	14.4	1935	2044	109
Winfield	14.8	1938	2044	106
Smith Mountain	586.0	1965	2040	75

Other Production Plant

APCo's depreciable investment in Other Production plant consists of the Ceredo and Dresden plants. The other production plants, capacities, estimated year to be retired and life span are shown on Table 5 below (and also on Schedule IV):

Table 5 - Estimated Other Production Plant Retirement Dates

Plant	Capacity (MW)	Year Installed	Year Retired	Life Span (Years)
Other Production Plant				
Ceredo	505.0	2001	2041	40
Dresden	580.0	2012	2047	35

APCo acquired the Ceredo plant from a subsidiary of Reliant Energy in 2005. This generating plant is a natural gas, simple cycle power plant with a nominal generating capacity of 505 megawatts. AEP's Pro Serve Subsidiary built the plant for Columbia Energy. It was completed and began commercial operation in 2001. There was no change in the estimated retirement year for Ceredo plant in the current depreciation study versus the prior depreciation study which used plant in service balances at December 31, 2013.

APCo acquired the unfinished Dresden plant in 2011. The Dresden plant was subsequently completed in 2012 when the plant was placed in service. There was no change in the estimated retirement year for Dresden plant in the current depreciation study versus the prior depreciation study which used plant in service balances at December 31, 2013. The Dresden plant is a natural gas combined cycle plant with a nominal generating capacity of 580 megawatts.

Actuarial Analysis – Transmission, Distribution and General Plant

The actuarial method of analyzing past experience represents the application to industrial property of statistical procedures developed in the life insurance field for investigating human mortality. It is distinguished from other methods of life estimation by the requirement that it is necessary to know the age of the property at the time of its retirement and the age of survivors, or plant remaining in service; that is, the installation date must be known for each particular retirement and for each particular survivor.

The application of this method involves the statistical procedure known as the "annual rate method" of analysis. This procedure relates retirements during each age interval to exposures at the beginning of that interval, the ratio of these being the annual retirement ratio. Subtracting each retirement ratio from unity yields a sequence of annual survival ratios from which a survivor curve can be determined. This is accomplished by the consecutive multiplication of the survivor ratios. The length of this curve depends primarily upon the age of the oldest property. Normally, if the period of years from the inception of the account to the time of the study is short in relation to the expected maximum life of the property, an incomplete or stub survivor curve results.

While there are a number of acceptable methods of smoothing and extending the stub survivor curve in order to compute the area under it from which the average life is determined, the well-known Iowa Type Curve Method was used in this study.

By this procedure, instead of mathematically smoothing and projecting the stub survivor curve to determine the average life of the group, it was assumed that the stub curve would have the same mortality characteristics as the type curve selected. The selection of the appropriate type curve and average life is accomplished by plotting the stub curve, superimposing on it Iowa curves of the various types and average lives drawn to the same scale, and then determining which Iowa type curve and average life best matches the stub.

The Actuarial Method of Life Analysis was used for the following accounts:

352.0 Transmission Structures & Improvements
353.0 Transmission Station Equipment
355.0 Transmission Poles & Fixtures
356.0 Transmission Overhead Conductor & Devices
361.0 Distribution Structures & Improvements
362.0 Distribution Station Equipment
390.0 General Structures & Improvements

The result of the actuarial analysis for the above accounts is detailed in the depreciation study work papers.

Simulated Plant Record Analysis – Transmission and Distribution Plant

The "Simulated Plant Record" (SPR) method designates a class of statistical techniques that provide an estimate of the age distribution, mortality dispersion and average service life of property accounts whose recorded history provides no indication of the age of the property units when retired from service. For each such account, the available property records usually reveal only the annual gross additions, annual retirements and balances with no indication of the age of either plant retirements or annual plant balances. For this study, the "Balances method" of analysis was used.

The SPR Balances Method is a trial and error procedure that attempts to duplicate the annual balance of a plant account by distributing the actual annual gross additions over time according to an assumed mortality distribution. Specifically, the dollars remaining in service at any date are estimated by multiplying each year's additions by the successive proportion surviving at each age as given by the assumed survivor characteristics. For a given year, the balance indicated is the accumulation of survivors from all vintages and this is compared with the actual book balance. This process is repeated for different survivor curves and average life combinations until a pattern is discovered which produces a series of "simulated balances" most nearly equaling the actual balances shown in a company's books.

This determination is based on the distribution producing the minimum sum of squared differences between the simulated balance and the actual balances over a test period of years.

The iterative nature of the simulated methods makes them ideally suited for computerized analysis. For each analysis of a given property account, the computer program provides a single page summary containing the results of each analysis indicating the “best fit” based on criteria selected by the user.

The results of the analysis using the Balance Method is shown in the depreciation study work papers. The analysis also shows the value of the Index of Variation of the difference that is calculated according to the Balances Method where a lower value for the Index of Variation indicates better agreement with the actual data.

The SPR Method of Life Analysis was utilized for the following accounts:

354.0 Transmission Towers & Fixtures
357.0 Transmission Underground Conduit
358.0 Transmission Underground Conductor
364.0 Distribution Poles, Towers & Fixtures
365.0 Distribution Overhead Conductor & Devices
366.0 Distribution Underground Conduit
367.0 Distribution Underground Conductor & Devices
368.0 Distribution Line Transformers
369.0 Distribution Services
370.0 Distribution Meters
371.0 Installation on Customers Premises
372.0 Leased Property on Customers Premises
373.0 Street Lighting & Signal Systems

Vintage Year Accounting – General Equipment

In 1998, the Companies began using a vintage year accounting method for general plant accounts 391 to 398 in accordance with Federal Energy

Regulatory Commission Accounting Release Number 15 (AR-15). This accounting method requires the amortization of vintage groups of property over their useful lives. AR-15 also requires that property be retired when it meets its average service life.

For these accounts, the study proposes that the current useful lives approved by this Commission be retained and used to continue amortization of the account balances.

4. Final Selection of Average Life and Curve Type

The final selection of average life and curve type for each depreciable plant account analyzed by the Actuarial and SPR Methods was primarily based on the results of the mortality analyses of past retirement history.

III. NET SALVAGE

1. Net Salvage - Steam Production Plant

The net salvage analysis for steam production plant included a review of APCo's experienced functional interim retirement, salvage and removal history for the period 1996-2017. This interim salvage analysis calculates annual life to date salvage, removal and net salvage percentages as compared to original cost retirements.

While this type of analysis was used to determine the net salvage applicable to interim retirements for steam production plant, the most significant net salvage amounts for generating plants occurs at the end of their life. Therefore, to assist in establishing total net salvage applicable to steam generating plant, APCo contracted with Brandenburg Industrial Service Company

(Brandenburg) to prepare terminal conceptual demolition cost estimates in 2017 for its steam production plants. The 2017 Brandenburg cost estimates were inflated to each plant's estimated retirement date. The estimates of demolition costs were incorporated into the net salvage ratios for Steam Production Plant. Brandenburg's demolition cost estimates do not include Asset Retirement Obligation (ARO) amounts associated with the removal of asbestos or any cost associated with the final disposition of landfills and ash ponds since accretion and depreciation associated with these AROs are included separately in APCo's cost of service.

The net salvage analysis for Mitchell plant included a review of the experienced functional interim retirement, salvage and removal history for the period 2001-2017. A terminal conceptual demolition cost estimate for Mitchell plant was prepared by Brandenburg in 2017. The 2017 Brandenburg cost estimate was inflated to Mitchell plant's estimated retirement date. The estimate of terminal demolition costs was incorporated into the net salvage ratios for Mitchell Plant. Brandenburg's demolition cost estimate does not include Asset Retirement Obligation (ARO) amounts associated with the removal of asbestos or any cost associated with the final disposition of landfills and ash ponds since accretion and depreciation associated with these AROs are included separately in WPCo's cost of service.

2. Net Salvage - Hydraulic Plant

The Hydraulic Plant negative net salvage percentage of -17% is based on an analysis of interim net salvage rates for the period from 1996 to 2017. The negative net salvage rate changed from -15% in the prior depreciation study to -17% in this study.

3. Net Salvage – Other Production Plant

The interim net salvage analysis for other production plant included a review of the Company's experienced functional interim retirement, salvage and removal history for the period 2006 - 2017.

The results of the interim net salvage analysis for Other Production Plant, was combined with a terminal net salvage estimate to produce a net salvage ratio used in the depreciation rate calculation. Similar to Steam Production Plant, APCo contracted with Brandenburg Industrial Service Company (Brandenburg) to prepare terminal conceptual demolition cost estimates in 2017 for its Ceredo and Dresden plants. The 2017 Brandenburg cost estimates were inflated to each plant's estimated retirement date. The estimates of demolition costs were incorporated into the net salvage ratios for Other Production Plant.

4. Net Salvage – Transmission, Distribution and General Plant

The net salvage percentages used in this report for Transmission, Distribution and General Plant are expressed as a percent of original cost and are based on APCo's experience and expertise. The net salvage analysis included a review of APCo's experienced interim retirement, salvage and removal history by account for the period 2001-2017 (for several accounts history was not available for this entire period). The salvage and removal percentages for each account were then netted to determine a net salvage percentage for each account.

The net salvage percents were converted to net salvage ratios (1 minus the net salvage percentage) and appear in Column IV on Schedule I (APCo) or Schedule V (WPCo) and were used to determine the total amount to be recovered through depreciation. The same net salvage ratio was also reflected in the determination of the calculated depreciation requirement (theoretical reserve).

5. Net Salvage – Ratios

The net salvage ratios shown in Column IV on Schedule I (APCO) or Schedule V (WPCo) of this report may be explained as follows:

a. Where the ratio is shown as unity (1.00), it was assumed that the net salvage in that particular account would be zero.

b. Where the ratio is less than unity, it was assumed that the salvage exceeded the removal costs. For example, if the net salvage were 20%, the net salvage ratio would be expressed as 0.80.

c. Where the ratio is greater than unity, it was assumed that the salvage was less than the cost of removal. For example, if the net salvage were minus 5%, the net salvage ratio would be expressed as 1.05.

IV. CALCULATION OF DEPRECIATION REQUIREMENT AT DECEMBER 31, 2017

A calculation of a depreciation requirement (theoretical reserve) for each plant account using the average service life, curve type and net salvage amount proposed in this study is provided in Column VI of Schedule I (APCo) or Schedule V (WPCo).

V. STUDY RESULTS - APCo

Production, Transmission, Distribution and General plant results for APCo are discussed below. In addition, Transmission, Distribution and General Plant average service life, retirement dispersion pattern and net salvage percentages used to calculate each primary plant account depreciation rate are shown on Schedule III. The mortality characteristics and net salvage values for the current rates are also shown. The changes to the mortality characteristics follow the trends shown by historical retirement experience. Gross salvage and gross cost of removal percentages for Transmission, Distribution and General plant were largely based on the history of the account for the period 2001-2017.

Steam Production Plant

The depreciation rates for Steam Production Plant increased from 2.93% to 3.68% due to a change in the depreciation rates for Clinch River Units 1 and 2. These two units were converted from coal fired to burn natural gas in 2016. APCo expects the converted Units 1 and 2 to operate until 2025. The depreciation rate increase for Clinch River Plant is due to the shorter recovery period through 2025 versus the 2040 retirement date used by the Commission Staff's depreciation study which was accepted by the Commission its order in Case No. 14-1151-E-D.

Additionally, a $221 million increase in plant investment at the Amos and Mountaineer Plants as compared to the investment reflected in the currently approved depreciation rates which were based on depreciable plant in service at December 31, 2013 contributes to the increase.

As in the prior study, demolition costs are included in the depreciation rates. The estimates of demolition costs were developed by Brandenburg Industrial Services Company.

Hydraulic Production Plant

The depreciation rates for Hydraulic plant increased from 2.81% to 3.73% mainly due to an increase in the net salvage ratio (1 minus the net salvage rate) from 1.15 to 1.17. Also contributing to the increase was a $28.4 million increase in plant investment at the facilities along with a decrease in average remaining life since the Company's last depreciation study using plant in service amounts at December 31, 2013.

Other Production Plant

Depreciation rates for Other Production plant increased from 2.42% to 2.58% primarily due to a $66 million increase in plant investment at the Dresden plant since the Company's last depreciation study using plant in service amounts at December 31, 2013

Transmission Plant

The depreciation rates for Transmission plant increased from 1.69% to 2.11% due to an increase in the net salvage ratio for accounts 352, 353, 354, and 356 and a decrease in the average service life for account 357. The increase was partially offset by a decrease in the net salvage ratio for account 355 and increases in the average service life for accounts 352, 353, 354, 356 and 358.

Distribution Plant

The depreciation rates for Distribution plant increased from 3.82% to 4.10% due to increases in the net salvage ratio for accounts 362, 364, 365, 368, 369, 371 and 373 and a decrease in the average service life for accounts 367 and 370. The rate increase was partially offset by an increase in average service life for accounts 361, 362, 364, 366 and 371.

General Plant

The depreciation rate for General plant increased from 2.37% to 2.74% due to an increase in the net salvage ratio for account 390.

VI. STUDY RESULTS - WPCo

Production, Transmission, Distribution and General plant results for WPCo are discussed below. In addition, Transmission, Distribution and General Plant average service life, retirement dispersion pattern and net salvage percentages used to calculate each primary plant account depreciation rate are shown on Schedule VII. The mortality characteristics and net salvage values for the current rates are also shown. The changes to the mortality characteristics follow the trends shown by historical retirement experience of APCo since an extensive amount of detailed retirement history was not available for WPCo. Gross salvage and gross cost of removal percentages for Transmission, Distribution and General plant were based on APCo’s historical experience for each account for the period 2001-2017.

Steam Production Plant

The depreciation rates for Mitchell Plant increased from 2.79% to 3.13% primarily due to a $111.7 million increase in plant investment as compared to the investment reflected in the currently approved depreciation rates which were based on depreciable plant in service at December 31, 2013.

Demolition costs are included in the depreciation rates. The estimates of demolition costs were developed by Brandenburg Industrial Services Company.

Transmission Plant

The depreciation rates for Transmission plant increased from 1.84% to 2.16% due to an increase in the net salvage ratio for accounts 352, 353, 354, and 356 and a decrease in the average service life for account 357. The increase was partially offset by a decrease in the net salvage ratio for account 355 and increases in the average service life for accounts 352, 353, 354, 356 and 358.

Distribution Plant

The depreciation rates for Distribution plant increased from 3.75% to 3.88% due to increases in the net salvage ratio for accounts 362, 364, 365, 368, 369, 371 and 373 and a decrease in the average service life for accounts 367 and 370. The rate increase was partially offset by an increase in average service life for accounts 361, 362, 364, 366 and 371.

General Plant

The depreciation rate for General plant increased from 1.45% to 2.23% due to an increase in the net salvage ratio for account 390.

VII. EXPLANATION OF COLUMN HEADINGS SCHEDULE I AND SCHEDULE V

Schedule I (APCo) and Schedule V (WPCo) show the determination of the proposed annual depreciation accrual rate by primary plant accounts by the straight line remaining life method. An explanation of the schedule follows:

Column I	-	Account number
Column II	-	Account title
Column III	-	Original Cost at December 31, 2017
Column IV	-	Net Salvage Ratio
Column V	-	Total to be Recovered (Column III) * (Column IV).
Column VI	-	Calculated Depreciation Requirement
Column VII	-	Allocated Accumulated Depreciation
Column VIII	-	Remaining Amount (Column V - Column VII)
Column IX	-	Average Remaining Life
Column X	-	Proposed Annual Accrual Amount
Column XI	-	Proposed Annual Accrual Percent or Depreciation Rate (Column X/Column III)

APPALACHIAN POWER COMPANY
SCHEDULE I - CALCULATION OF DEPRECIATION RATES BY THE REMAINING LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2017

WV

ACCT NO (I)	ACCOUNT TITLE (II)	ORIGINAL COST (III)	NET SALVG. RATIO (IV)	TOTAL TO BE RECOVERED (V)	THEORETICAL RESERVE (VI)	ACCUMULATED DEPRECIATION (VII)	REMAINING AMOUNT (VIII)	AVG. REMAIN LIFE (IX)	ANNUAL ACCRUAL (X)	DEPR. RATE (XI)
	STEAM PRODUCTION PLANT (1)									
	AMOS UNITS 1&2									
311	Structures & Improvements	53,839,329	1.02	54,916,116	28,275,190	23,539,503	31,376,613	22.17	1,415,273	2.63%
312	Boiler Plant Equipment	1,330,320,941	1.05	1,396,836,988	528,521,850	440,002,055	956,834,933	21.21	45,112,444	3.39%
312	Boiler Plant Equip. SCR Catalyst (1)	20,163,062	1.05	21,171,215	14,021,859	11,673,400	9,497,815	13.00	1,628,555	8.08%
314	Turbogenerator Units	122,788,151	1.06	130,155,440	68,362,353	56,912,644	73,242,796	20.60	3,555,476	2.90%
315	Accessory Electrical Equip.	55,027,725	1.03	56,678,557	29,149,331	24,267,238	32,411,319	21.92	1,478,619	2.69%
316	Misc. Power Plant Equip.	5,033,859	1.04	5,235,213	2,923,842	2,434,141	2,801,072	21.36	131,136	2.61%
	Total	1,587,173,067	1.05	1,664,993,529	671,254,425	558,828,981	1,106,164,548		53,321,503	3.36%
	AMOS UNIT 3									
311	Structures & Improvements	108,166,036	1.02	110,329,357	53,836,545	50,751,485	59,577,872	22.17	2,687,319	2.48%
312	Boiler Plant Equipment	1,556,642,863	1.05	1,634,475,006	569,430,002	433,863,147	1,200,611,859	21.21	56,605,934	3.64%
312	Boiler Plant Equip. SCR Catalyst (1)	17,384,535	1.05	18,253,762	15,899,026	8,640,175	9,613,587	10.00	1,825,376	10.50%
314	Turbogenerator Units	151,912,805	1.06	161,027,573	65,183,366	35,933,103	125,094,470	20.60	6,072,547	4.00%
315	Accessory Electrical Equip.	33,896,113	1.03	34,912,996	20,067,354	16,906,380	18,006,616	21.92	821,470	2.42%
316	Misc. Power Plant Equip.	27,652,340	1.04	28,758,434	14,617,546	11,828,215	16,930,219	21.36	792,613	2.87%
	Total	1,895,654,692	1.05	1,987,757,128	739,033,839	557,922,505	1,429,834,623		68,805,259	3.63%
	CLINCH RIVER (2)									
311	Structures & Improvements	25,647,783	1.03	26,417,216	20,262,550	16,797,504	9,619,712	7.46	1,289,506	5.03%
312	Boiler Plant Equipment	213,147,393	1.04	221,673,289	140,624,337	56,978,662	164,694,627	7.36	22,376,987	10.50%
314	Turbogenerator Units	40,568,509	1.04	42,191,249	34,714,968	36,954,206	5,237,043	7.29	718,387	1.77%
315	Accessory Electrical Equip.	9,748,492	1.03	10,040,947	8,237,793	8,576,239	1,464,708	7.44	196,869	2.02%
316	Misc. Power Plant Equip.	5,025,922	1.04	5,226,959	3,839,754	474,860	4,752,099	7.37	644,790	12.83%
	Total	294,138,099	1.04	305,549,660	207,679,402	119,781,471	185,768,189		25,226,539	8.58%
	MOUNTAINEER									
311	Structures & Improvements	198,425,642	1.03	204,378,411	97,739,923	73,909,511	130,468,900	22.17	5,884,930	2.97%
312	Boiler Plant Equipment	1,133,479,283	1.05	1,190,153,247	557,175,555	423,599,264	766,553,983	21.21	36,141,159	3.19%
312	Boiler Plant Equip. SCR Catalyst (1)	18,739,798	1.05	19,676,788	11,827,936	4,514,826	15,161,962	9.00	2,186,310	11.67%
314	Turbogenerator Units	100,787,690	1.07	107,842,828	58,463,805	54,479,098	53,363,730	20.60	2,590,472	2.57%
315	Accessory Electrical Equip.	76,498,100	1.03	78,793,043	46,285,166	46,276,012	32,517,031	21.92	1,483,441	1.94%
316	Misc. Power Plant Equip.	21,517,408	1.05	22,593,278	12,065,520	10,728,655	11,864,623	21.36	555,460	2.58%
	Total	1,549,447,921	1.05	1,623,437,596	783,557,905	613,507,366	1,009,930,230		48,841,772	3.15%
	OTHER									
311	Centralized Maintenence	85,770	1.00	85,770	47,035	48,146	37,624	22.17	1,697	1.98%
316	Central Machine Shop	17,065,153	1.00	17,065,153	7,950,083	7,483,181	9,581,972	21.36	448,594	2.63%
311	Little Broad Run Ash Disposal	267,028	1.00	267,028	67,499	42,373	224,655	22.17	10,133	3.79%
312	Little Broad Run Ash Disposal	50,333,699	1.00	50,333,699	14,058,546	8,149,783	42,183,916	21.21	1,988,869	3.95%
315	Little Broad Run Ash Disposal	64,843	1.00	64,843	13,006	8,480	56,363	21.92	2,571	3.96%
	Total	67,816,493	1.00	67,816,493	22,136,169	15,731,963	52,084,530		2,451,864	3.62%
	Total Steam Production Plant	**5,394,230,272**	**1.05**	**5,649,554,406**	**2,423,661,740**	**1,865,772,286**	**3,783,782,120**	**19.05**	**198,646,937**	**3.68%**
	HYDRAULIC PRODUCTION PLANT (3)									
	BUCK									
331	Structures & Improvements	370,373	1.17	433,336	389,787	281,346	151,990	6.46	23,528	6.35%
332	Reservoirs, Dams & Waterways	7,102,900	1.17	8,310,393	6,394,887	3,839,255	4,471,138	6.47	691,057	9.73%
333	Waterwheels, Turbines & Gen.	1,936,552	1.17	2,265,766	1,819,996	1,581,282	684,484	6.40	106,951	5.52%
334	Accessory Electrical Equip.	2,514,434	1.17	2,941,888	2,260,427	1,780,853	1,161,035	6.34	183,129	7.28%
335	Misc. Power Plant Equip.	581,739	1.17	680,635	430,510	206,065	474,570	6.42	73,921	12.71%
336	Roads, Railroads & Bridges	3,437	1.17	4,021	3,754	2,953	1,068	6.50	164	4.77%
	Total	12,509,435	1.17	14,636,039	11,299,361	7,691,754	6,944,285		1,078,750	8.62%

APPALACHIAN POWER COMPANY
SCHEDULE I - CALCULATION OF DEPRECIATION RATES BY THE REMAINING LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2017

WV

ACCT NO (I)	ACCOUNT TITLE (II)	ORIGINAL COST (III)	NET SALVG. RATIO (IV)	TOTAL TO BE RECOVERED (V)	THEORETICAL RESERVE (VI)	ACCUMULATED DEPRECIATION (VII)	REMAINING AMOUNT (VIII)	AVG. REMAIN LIFE (IX)	ANNUAL ACCRUAL (X)	DEPR. RATE (XI)
	BYLLESBY									
331	Structures & Improvements	1,066,712	1.17	1,248,053	1,028,009	535,948	712,105	6.46	110,233	10.33%
332	Reservoirs, Dams & Waterways	6,231,513	1.17	7,290,870	5,268,927	2,461,259	4,829,611	6.47	746,462	11.98%
333	Waterwheels, Turbines & Gen.	3,638,481	1.17	4,257,023	3,215,549	1,508,740	2,748,283	6.40	429,419	11.80%
334	Accessory Electrical Equip.	1,078,296	1.17	1,261,606	1,061,341	670,038	591,568	6.34	93,307	8.65%
335	Misc. Power Plant Equip.	953,783	1.17	1,115,926	768,821	443,940	671,986	6.42	104,671	10.97%
	Total	12,968,785	1.17	15,173,478	11,342,647	5,619,925	9,553,553		1,484,092	11.44%
	CLAYTOR									
331	Structures & Improvements	2,734,525	1.17	3,199,394	1,743,227	1,304,979	1,894,415	23.03	82,259	3.01%
332	Reservoirs, Dams & Waterways	12,617,216	1.17	14,762,143	9,658,469	8,653,507	6,108,636	23.06	264,902	2.10%
333	Waterwheels, Turbines & Gen.	3,150,372	1.17	3,685,935	2,379,520	1,762,229	1,923,706	22.23	86,536	2.75%
334	Accessory Electrical Equip.	3,073,876	1.17	3,596,435	2,024,927	1,908,873	1,687,562	21.35	79,043	2.57%
335	Misc. Power Plant Equip.	2,860,803	1.17	3,347,140	1,448,485	1,261,519	2,085,621	22.48	92,777	3.24%
336	Roads, Railroads & Bridges	31,799	1.17	37,205	28,433	31,321	5,884	23.50	250	0.79%
	Total	24,468,591	1.17	28,628,251	17,283,061	14,922,428	13,705,823		605,767	2.48%
	LEESVILLE									
331	Structures & Improvements	3,548,822	1.17	4,152,122	2,455,134	2,138,977	2,013,145	22.07	91,216	2.57%
332	Reservoirs, Dams & Waterways	11,050,141	1.17	12,928,665	7,961,288	7,883,061	5,045,604	22.10	228,308	2.07%
333	Waterwheels, Turbines & Gen.	3,740,697	1.17	4,376,615	2,874,090	2,883,831	1,492,784	21.34	69,952	1.87%
334	Accessory Electrical Equip.	1,153,027	1.17	1,349,042	694,449	471,794	877,248	20.53	42,730	3.71%
335	Misc. Power Plant Equip.	1,881,843	1.17	2,201,756	1,121,423	875,073	1,326,683	21.56	61,534	3.27%
336	Roads, Railroads & Bridges	80,790	1.17	94,524	66,477	79,911	14,613	22.50	649	0.80%
	Total	21,455,320	1.17	25,102,724	15,172,861	14,332,647	10,770,077		494,389	2.30%
	LONDON									
331	Structures & Improvements	616,624	1.17	721,450	407,934	150,992	570,458	25.90	22,025	3.57%
332	Reservoirs, Dams & Waterways	1,377,081	1.17	1,611,185	853,907	684,666	926,519	25.94	35,718	2.59%
333	Waterwheels, Turbines & Gen.	5,409,717	1.17	6,329,369	2,241,720	977,214	5,352,155	24.89	215,032	3.97%
334	Accessory Electrical Equip.	1,904,344	1.17	2,228,082	1,200,934	977,108	1,250,974	23.76	52,650	2.76%
335	Misc. Power Plant Equip.	480,004	1.17	561,605	216,676	134,926	426,679	25.20	16,932	3.53%
336	Roads, Railroads & Bridges	48,853	1.17	57,158	37,882	38,417	18,741	26.50	707	1.45%
	Total	9,836,623	1.17	11,508,849	4,959,053	2,963,323	8,545,526		343,064	3.49%
	MARMET									
331	Structures & Improvements	703,983	1.17	823,660	472,156	344,916	478,744	25.90	18,484	2.63%
332	Reservoirs, Dams & Waterways	1,876,778	1.17	2,195,830	993,131	684,532	1,511,298	25.94	58,261	3.10%
333	Waterwheels, Turbines & Gen.	5,147,749	1.17	6,022,866	2,064,347	358,960	5,663,906	24.89	227,558	4.42%
334	Accessory Electrical Equip.	2,189,767	1.17	2,562,027	1,376,560	1,094,777	1,467,250	23.76	61,753	2.82%
335	Misc. Power Plant Equip.	641,637	1.17	750,715	323,672	230,908	519,807	25.20	20,627	3.21%
336	Roads, Railroads & Bridges	1,275	1.17	1,492	992	1,018	474	26.50	18	1.41%
	Total	10,561,189	1.17	12,356,591	5,230,858	2,715,111	9,641,480		386,701	3.66%
	NIAGARA									
331	Structures & Improvements	643,402	1.17	752,780	511,801	139,193	613,587	6.46	94,983	14.76%
332	Reservoirs, Dams & Waterways	6,428,867	1.17	7,521,774	5,687,403	3,296,558	4,225,216	6.47	653,047	10.16%
333	Waterwheels, Turbines & Gen.	628,317	1.17	735,131	609,063	555,031	180,100	6.40	28,141	4.48%
334	Accessory Electrical Equip.	492,170	1.17	575,839	390,800	126,643	449,196	6.34	70,851	14.40%
335	Misc. Power Plant Equip.	236,941	1.17	277,221	219,343	179,919	97,302	6.42	15,156	6.40%
	Total	8,429,697	1.17	9,862,745	7,418,410	4,297,344	5,565,401		862,178	10.23%
	SMITH MOUNTAIN									
331	Structures & Improvements	15,129,256	1.17	17,701,230	10,917,654	11,442,986	6,258,244	22.07	283,563	1.87%
332	Reservoirs, Dams & Waterways	26,723,426	1.17	31,266,408	20,796,899	25,496,080	5,770,328	22.10	261,101	0.98%
333	Waterwheels, Turbines & Gen.	73,463,990	1.17	85,952,868	44,743,383	35,834,241	50,118,627	21.34	2,348,577	3.20%
334	Accessory Electrical Equip.	10,450,047	1.17	12,226,555	6,033,336	4,738,946	7,487,609	20.53	364,715	3.49%
335	Misc. Power Plant Equip.	9,525,683	1.17	11,145,049	4,876,141	3,902,535	7,242,514	21.56	335,924	3.53%
336	Roads, Railroads & Bridges	1,052,133	1.17	1,230,996	836,446	1,034,128	196,868	22.50	8,750	0.83%
	Total Smith Mountain	136,344,535	1.17	159,523,106	88,203,859	82,448,916	77,074,190		3,602,630	2.64%

APPALACHIAN POWER COMPANY
SCHEDULE I - CALCULATION OF DEPRECIATION RATES BY THE REMAINING LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2017

WV

ACCT NO (I)	ACCOUNT TITLE (II)	ORIGINAL COST (III)	NET SALVG. RATIO (IV)	TOTAL TO BE RECOVERED (V)	THEORETICAL RESERVE (VI)	ACCUMULATED DEPRECIATION (VII)	REMAINING AMOUNT (VIII)	AVG. REMAIN LIFE (IX)	ANNUAL ACCRUAL (X)	DEPR. RATE (XI)
	WINFIELD									
331	Structures & Improvements	2,754,498	1.17	3,222,763	825,590	414,216	2,808,547	25.90	108,438	3.94%
332	Reservoirs, Dams & Waterways	2,213,073	1.17	2,589,295	1,257,951	938,523	1,650,772	25.94	63,638	2.88%
333	Waterwheels, Turbines & Gen.	4,621,476	1.17	5,407,127	2,050,933	742,119	4,665,008	24.89	187,425	4.06%
334	Accessory Electrical Equip.	261,339	1.17	305,767	125,895	49,803	255,964	23.76	10,773	4.12%
335	Misc. Power Plant Equip.	3,178,347	1.17	3,718,666	1,961,816	1,658,028	2,060,638	25.20	81,771	2.57%
336	Roads, Railroads & Bridges	23,567	1.17	27,573	12,414	10,575	16,998	26.50	641	2.72%
	Total	13,052,300	1.17	15,271,191	6,234,599	3,813,264	11,457,927		452,686	3.47%
	Total Hydraulic Production	**249,626,475**	**1.17**	**292,062,976**	**167,144,709**	**138,804,712**	**153,258,264**	**16.46**	**9,310,257**	**3.73%**
	OTHER PRODUCTION PLANT									
	CEREDO									
341	Structures & Improvements	1,652,232	1.01	1,668,754	602,123	1,178,899	489,855	22.09	22,175	1.34%
344	Generators	179,404,448	1.01	181,198,492	62,728,527	125,989,914	55,208,578	22.89	2,411,908	1.34%
345	Accessory Electrical Equip.	18,824,142	1.01	19,012,383	6,633,113	13,006,790	6,005,593	22.75	263,982	1.40%
346	Misc. Power Plant Equip.	1,080,430	1.02	1,102,039	350,279	307,110	794,929	18.50	42,969	3.98%
	Total Ceredo Plant	200,961,252	1.01	202,981,669	70,314,042	140,482,713	62,498,956		2,741,034	1.36%
	DRESDEN									
341	Structures & Improvements	45,788,946	1.01	46,246,835	7,296,120	4,749,875	41,496,960	27.28	1,521,150	3.32%
342	Fuel Holders, Producers & Access.	25,974,514	1.00	25,974,514	3,864,226	3,821,633	22,152,881	29.41	753,243	2.90%
344	Generators	302,947,239	1.01	305,976,711	43,263,855	38,233,520	267,743,191	28.54	9,381,331	3.10%
345	Accessory Electrical Equip.	23,253,887	1.01	23,486,426	3,707,281	3,237,894	20,248,532	28.33	714,738	3.07%
346	Misc. Power Plant Equip.	28,457,081	1.03	29,310,793	5,388,842	3,818,473	25,492,320	23.35	1,091,748	3.84%
	Total Dresden Plant	426,421,667	1.01	430,995,280	63,520,324	53,861,395	377,133,885		13,462,210	3.16%
	Total Other Production Plant	**627,382,919**	**1.01**	**633,976,949**	**133,834,366**	**194,344,108**	**439,632,841**	**27.13**	**16,203,244**	**2.58%**
	Total Production Plant	**6,271,239,666**	**1.05**	**6,575,594,331**	**2,724,640,815**	**2,198,921,106**	**4,376,673,225**	**19.52**	**224,160,438**	**3.57%**
	TRANSMISSION PLANT									
351	Energy Storage Equipment (4)	3,054,157	1.00	3,054,157	2,313,888	1,473,498	1,580,659	3.64	434,247	14.22%
352	Structures & Improvements	53,745,705	1.15	61,807,561	24,944,316	28,561,081	33,246,480	38.17	871,011	1.62%
353	Station Equipment	1,363,303,699	1.08	1,472,367,995	333,202,943	296,159,662	1,176,208,333	36.36	32,348,964	2.37%
354	Towers & Fixtures	472,289,197	1.15	543,132,577	155,717,519	163,361,295	379,771,282	50.64	7,499,433	1.59%
355	Poles & Fixtures	365,254,244	1.12	409,084,753	67,216,831	61,668,154	347,416,599	35.10	9,897,909	2.71%
356	OH Conductor & Devices	605,491,610	1.03	623,656,358	174,227,740	177,764,212	445,892,146	48.28	9,235,546	1.53%
357	Underground Conduit	279,063	1.00	279,063	223,112	185,711	93,352	9.02	10,349	3.71%
358	Underground Conductor	7,362,601	1.00	7,362,601	3,758,520	2,830,029	4,532,572	11.75	385,751	5.24%
	Total Transmission Plant	**2,870,780,276**	**1.09**	**3,120,745,065**	**761,604,869**	**732,003,642**	**2,388,741,423**	**39.36**	**60,683,210**	**2.11%**
	DISTRIBUTION PLANT - VA (5)									
361	Structures & Improvements	20,641,688	1.12	23,118,691	7,600,315	7,884,732	15,233,959	35.60	392,273	1.90%
362	Station Equipment	299,858,775	1.16	347,836,179	66,655,708	69,672,652	278,163,527	36.09	7,553,621	2.52%
364	Poles, Towers, & Fixtures	376,885,792	1.67	629,399,273	190,361,712	225,940,506	403,458,767	23.38	17,965,672	4.77%
365	Overhead Conductor & Devices	454,010,558	1.16	526,652,247	101,573,296	88,318,457	438,333,790	27.83	15,339,873	3.38%
366	Underground Conduit	63,827,711	1.00	63,827,711	17,757,167	20,814,970	43,012,741	40.11	1,104,138	1.73%
367	Underground Conductor	176,447,463	1.00	176,447,463	42,789,679	52,333,249	124,114,214	37.19	3,617,162	2.05%
368	Line Transformers	355,171,104	1.20	426,205,325	137,208,277	125,617,600	300,587,725	18.39	16,506,559	4.65%
369	Services	174,005,477	1.26	219,246,901	67,934,399	73,043,510	146,203,391	21.33	7,338,237	4.22%
370	Meters	84,201,217	1.10	92,621,339	35,735,283	11,686,751	80,934,588	5.85	10,463,016	12.43%
371	Installations on Custs. Prem.	35,899,290	1.22	43,797,134	18,134,204	22,210,850	21,586,284	7.27	3,337,973	9.30%
372	Leased Property on Cust. Prem.	771	1.00	771	542	621	150	7.43	44	5.70%
373	Street Lighting & Signal Sys.	18,688,467	1.31	24,481,892	11,118,897	10,250,087	14,231,805	12.26	1,527,603	8.17%
	Total Distribution Plant - VA	2,059,638,313	1.25	2,573,634,925	696,869,479	707,773,985	1,865,860,940	21.91	85,146,171	4.13%

APPALACHIAN POWER COMPANY
SCHEDULE I - CALCULATION OF DEPRECIATION RATES BY THE REMAINING LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2017

WV

ACCT NO (I)	ACCOUNT TITLE (II)	ORIGINAL COST (III)	NET SALVG. RATIO (IV)	TOTAL TO BE RECOVERED (V)	THEORETICAL RESERVE (VI)	ACCUMULATED DEPRECIATION (VII)	REMAINING AMOUNT (VIII)	AVG. REMAIN LIFE (IX)	ANNUAL ACCRUAL (X)	DEPR. RATE (XI)
DISTRIBUTION PLANT - WV										
361	Structures & Improvements	17,044,918	1.12	19,090,308	7,286,102	7,558,760	11,531,548	35.60	323,920	1.90%
362	Station Equipment	217,442,695	1.16	252,233,526	52,188,036	54,550,149	197,683,377	36.09	5,477,511	2.52%
363	Energy Storage Equipment (6)	5,402,894	1.00	5,402,894	3,350,076	3,131,355	2,271,539	5.70	398,516	7.38%
364	Poles, Towers, & Fixtures	365,925,167	1.67	611,095,029	171,263,808	203,273,185	407,821,844	23.38	17,443,193	4.77%
365	Overhead Conductor & Devices	412,983,405	1.16	479,060,750	104,346,924	90,730,139	388,330,611	27.83	13,953,669	3.38%
366	Underground Conduit	48,974,647	1.00	48,974,647	12,790,880	14,993,483	33,981,164	40.11	847,199	1.73%
367	Underground Conductor	99,396,168	1.00	99,396,168	19,310,378	23,617,256	75,778,912	37.19	2,037,615	2.05%
368	Line Transformers	227,926,361	1.20	273,511,633	85,971,248	78,708,822	194,802,811	18.39	10,592,866	4.65%
369	Services	158,433,513	1.26	199,626,226	53,114,648	57,109,217	142,517,009	21.33	6,681,529	4.22%
370	Meters (7)	44,209,707	1.10	48,630,678	50,432,202	16,493,184	32,137,494	5.85	5,493,589	12.43%
371	Installations on Custs. Prem.	23,204,627	1.22	28,309,645	10,306,847	12,623,870	15,685,775	7.27	2,157,603	9.30%
373	Street Lighting & Signal Sys.	9,540,751	1.31	12,498,384	3,186,209	2,937,244	9,561,140	12.26	779,865	8.17%
	Total Distribution Plant - WV	1,630,484,853	1.27	2,077,829,888	573,547,358	565,726,664	1,512,103,224	22.85	66,187,075	4.06%
DISTRIBUTION PLANT - TN										
370	Meters	47,141	1.10	51,855	47,141	47,462	4,393	5.85	751	1.59%
	Total Distribution Plant - TN	47,141		51,855	47,141	47,462	4,393		751	1.59%
	Total Distribution Plant	**3,690,170,307**	**1.26**	**4,651,516,668**	**1,270,463,978**	**1,273,548,111**	**3,377,968,557**	**22.32**	**151,333,997**	**4.10%**
GENERAL PLANT										
390	Structures & Improvements	116,542,664	0.88	102,557,544	42,943,142	48,251,624	54,305,920	24.41	2,224,741	1.91%
391	Office Furniture & Equipment	8,897,328	1.00	8,897,328	3,244,277	3,518,879	5,378,449	19.06	282,185	3.17%
392	Transportation Equipment	8,674	1.00	8,674	729	1,377	7,297	24.73	295	3.40%
393	Stores Equipment	1,764,272	1.00	1,764,272	486,552	502,732	1,261,540	39.83	31,673	1.80%
394	Tools Shop & Garage Equipment	32,170,663	1.10	35,387,729	9,238,169	9,117,070	26,270,659	31.77	826,901	2.57%
395	Laboratory Equipment	2,830,764	1.00	2,830,764	1,951,186	1,524,334	1,306,430	11.50	113,603	4.01%
396	Power Operated Equipment	0	1.00	0	0	0	0	0.00	0	0.00%
397	Communication Equipment	43,098,607	1.03	44,391,565	19,136,830	15,099,913	29,291,652	13.65	2,145,909	4.98%
398	Miscellaneous Equipment	6,893,105	1.00	6,893,105	2,652,436	2,888,691	4,004,414	21.53	185,992	2.70%
	Total General Plant	**212,206,077**	**0.96**	**202,730,982**	**79,653,321**	**80,904,620**	**121,826,362**	**20.96**	**5,811,299**	**2.74%**
Total Depreciable Plant		**13,044,396,326**	**1.12**	**14,550,587,045**	**4,836,362,983**	**4,285,377,479**	**10,265,209,566**	**23.23**	**441,988,944**	**3.39%**

Notes:

1. In May 2015, APCo retired the Philip Sporn Plant (APCo owned Units 1 and 3), Glen Lyn Units 5 and 6, the Kanawha River Plant, Clinch River Unit 3 and the coal related property at Clinch River Units 1&2. Clinch River Units 1&2 were converted to burn natural gas in 2016. The SCR Catalyst is using a whole life type depreciation rate calculation.

2. Clinch River Units 1 and 2 were converted to burn natural gas in 2016.

3. In April 2016, the Reusens Hydro facility was sold to Eagle Creek Renewable Energy, LLC, an unaffiliated company.

4. Account 351, Electric Storage Equipment - Transmission was established in 2013 as per FERC Order 784 regarding Accounting and Financial Reporting for New Electric Storage Technologies. The amount in account 351 represents the Company's investment in a sodium sulphur (NaS) storage battery at its Chemical 138KV Substation.

5. Using West Virginia depreciation rates for Virginia Distribution property for total Company comparison purposes, except for account 372 where West Virginia has no investment. This account uses Virginia's depreciation rate.

6. Account 363 Energy Storage Equipment represents a sodium sulphur (NaS) battery at APCo's WV Balls Gap 138KV Substation.

7. Account 370 Excludes AMI Meters (account 37016) located in Virginia.

APPALACHIAN POWER COMPANY
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SCHEDULE II - COMPARE DEPRECIATION EXPENSE USING CURRENT AND STUDY RATES
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2017

WV

NO. (1)	TITLE (2)	ORIGINAL COST (3)	CURRENT APPROVED RATE (4)	ANNUAL ACCRUAL (5)	STUDY RATE (6)	STUDY ACCRUAL (7)	DIFFERENCE (DECREASE) (8)
Steam Production Plant (1)							
	AMOS UNITS 1&2						
311	Structures & Improvements	53,839,329	1.45%	780,670	2.63%	1,415,273	634,603
312	Boiler Plant Equipment	1,330,320,941	2.88%	38,313,243	3.39%	45,112,444	6,799,201
312	Boiler Plant Equip. SCR Catalyst	20,163,062	9.09%	1,832,822	8.08%	1,628,555	-204,267
314	Turbogenerator Units	122,788,151	3.73%	4,579,998	2.90%	3,555,476	-1,024,522
315	Accessory Electrical Equipment	55,027,725	3.04%	1,672,843	2.69%	1,478,619	-194,224
316	Misc. Power Plant Equip.	5,033,859	3.00%	151,016	2.61%	131,136	-19,880
	Total	1,587,173,067	2.98%	47,330,592	3.36%	53,321,503	5,990,911
	AMOS UNIT 3						
311	Structures & Improvements	108,166,036	2.22%	2,401,286	2.48%	2,687,319	286,033
312	Boiler Plant Equipment	1,556,642,863	3.19%	49,656,907	3.64%	56,605,934	6,949,027
312	Boiler Plant Equip. SCR Catalyst	17,384,535	12.50%	2,173,067	10.50%	1,825,376	-347,691
314	Turbogenerator Units	151,912,805	2.93%	4,451,045	4.00%	6,072,547	1,621,502
315	Accessory Electrical Equipment	33,896,113	1.81%	613,520	2.42%	821,470	207,950
316	Misc. Power Plant Equip.	27,652,340	2.43%	671,952	2.87%	792,613	120,661
	Total	1,895,654,692	3.16%	59,967,777	3.63%	68,805,259	8,837,482
	CLINCH RIVER (2)						
311	Structures & Improvements	25,647,783	1.13%	289,820	5.03%	1,289,506	999,686
312	Boiler Plant Equipment	213,147,393	2.26%	4,817,131	10.50%	22,376,987	17,559,856
314	Turbogenerator Units	40,568,509	1.05%	425,969	1.77%	718,387	292,418
315	Accessory Electrical Equipment	9,748,492	1.08%	105,284	2.02%	196,869	91,585
316	Misc. Power Plant Equip.	5,025,922	1.74%	87,451	12.83%	644,790	557,339
	Total	294,138,099	1.95%	5,725,655	8.58%	25,226,539	19,500,884
	MOUNTAINEER						
311	Structures & Improvements	198,425,642	2.65%	5,258,280	2.97%	5,884,930	626,650
312	Boiler Plant Equipment	1,133,479,283	2.80%	31,737,420	3.19%	36,141,159	4,403,739
312	Boiler Plant Equip. SCR Catalyst	18,739,798	12.50%	2,342,475	11.67%	2,186,310	-156,165
314	Turbogenerator Units	100,787,690	2.08%	2,096,384	2.57%	2,590,472	494,088
315	Accessory Electrical Equipment	76,498,100	1.54%	1,178,071	1.94%	1,483,441	305,370
316	Misc. Power Plant Equip.	21,517,408	2.13%	458,321	2.58%	555,460	97,139
	Total	1,549,447,921	2.78%	43,070,951	3.15%	48,841,772	5,770,821
	OTHER						
311	Centralized Maintenance	85,770	2.61%	2,239	1.98%	1,697	-542
316	Central Machine Shop	17,065,153	2.80%	477,824	2.63%	448,594	-29,230
311	Little Broad Run Ash Disposal	267,028	3.48%	9,293	3.79%	10,133	840
312	Little Broad Run Ash Disposal	50,333,699	3.24%	1,630,812	3.95%	1,988,869	358,057
315	Little Broad Run Ash Disposal	64,843	3.64%	2,360	3.96%	2,571	211
	Total	67,816,493	3.13%	2,122,528	3.62%	2,451,864	329,336
	Total Steam Production Plant	**5,394,230,272**	**2.93%**	**158,217,503**	**3.68%**	**198,646,937**	**40,429,434**
Hydraulic Production Plant (3)							
	BUCK						
331	Structures & Improvements	370,373	3.98%	14,741	6.35%	23,528	8,787
332	Reservoirs, Dams & Waterways	7,102,900	5.92%	420,492	9.73%	691,057	270,565
333	Waterwheels, Turbines & Generators	1,936,552	4.44%	85,983	5.52%	106,951	20,968
334	Accessory Electric Equipment	2,514,434	6.33%	159,164	7.28%	183,129	23,965
335	Micellaneous Power Plant Equipment	581,739	7.88%	45,841	12.71%	73,921	28,080
336	Roads, Railroads & Bridges	3,437	3.06%	105	4.77%	164	59
	Total Buck Plant	12,509,435	5.81%	726,326	8.62%	1,078,750	352,424
	BYLLESBY						
331	Structures & Improvements	1,066,712	6.45%	68,803	10.33%	110,233	41,430
332	Reservoirs, Dams & Waterways	6,231,513	8.79%	547,750	11.98%	746,462	198,712
333	Waterwheels, Turbines & Generators	3,638,481	6.88%	250,327	11.80%	429,419	179,092
334	Accessory Electric Equipment	1,078,296	3.09%	33,319	8.65%	93,307	59,988
335	Micellaneous Power Plant Equipment	953,783	8.09%	77,161	10.97%	104,671	27,510
	Total Byllesby Plant	12,968,785	7.54%	977,360	11.44%	1,484,092	506,732

APPALACHIAN POWER COMPANY
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SCHEDULE II - COMPARE DEPRECIATION EXPENSE USING CURRENT AND STUDY RATES
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2017

WV

NO. (1)	TITLE (2)	ORIGINAL COST (3)	CURRENT APPROVED RATE (4)	ANNUAL ACCRUAL (5)	STUDY RATE (6)	STUDY ACCRUAL (7)	DIFFERENCE (DECREASE) (8)
	CLAYTOR						
331	Structures & Improvements	2,734,525	1.91%	52,229	3.01%	82,259	30,030
332	Reservoirs, Dams & Waterways	12,617,216	1.17%	147,621	2.10%	264,902	117,281
333	Waterwheels, Turbines & Generators	3,150,372	1.27%	40,010	2.75%	86,536	46,526
334	Accessory Electric Equipment	3,073,876	2.34%	71,929	2.57%	79,043	7,114
335	Micellaneous Power Plant Equipment	2,860,803	2.87%	82,105	3.24%	92,777	10,672
336	Roads, Railroads & Bridges	31,799	0.69%	219	0.79%	250	31
	Total Claytor Plant	24,468,591	1.61%	394,113	2.48%	605,767	211,654
	LEESVILLE						
331	Structures & Improvements	3,548,822	0.81%	28,745	2.57%	91,216	62,471
332	Reservoirs, Dams & Waterways	11,050,141	1.77%	195,587	2.07%	228,308	32,721
333	Waterwheels, Turbines & Generators	3,740,697	1.30%	48,629	1.87%	69,952	21,323
334	Accessory Electric Equipment	1,153,027	2.57%	29,633	3.71%	42,730	13,097
335	Micellaneous Power Plant Equipment	1,881,843	2.53%	47,611	3.27%	61,534	13,923
336	Roads, Railroads & Bridges	80,790	0.60%	485	0.80%	649	164
	Total Leesville Plant	21,455,320	1.63%	350,690	2.30%	494,389	143,699
	LONDON						
331	Structures & Improvements	616,624	3.12%	19,239	3.57%	22,025	2,786
332	Reservoirs, Dams & Waterways	1,377,081	2.45%	33,738	2.59%	35,718	1,980
333	Waterwheels, Turbines & Generators	5,409,717	3.02%	163,373	3.97%	215,032	51,659
334	Accessory Electric Equipment	1,904,344	2.63%	50,084	2.76%	52,650	2,566
335	Micellaneous Power Plant Equipment	480,004	3.02%	14,496	3.53%	16,932	2,436
336	Roads, Railroads & Bridges	48,853	1.38%	674	1.45%	707	33
	Total London Plant	9,836,623	2.86%	281,604	3.49%	343,064	61,460
	MARMET						
331	Structures & Improvements	703,983	1.97%	13,868	2.63%	18,484	4,616
332	Reservoirs, Dams & Waterways	1,876,778	2.95%	55,365	3.10%	58,261	2,896
333	Waterwheels, Turbines & Generators	5,147,749	3.22%	165,758	4.42%	227,558	61,800
334	Accessory Electric Equipment	2,189,767	2.70%	59,124	2.82%	61,753	2,629
335	Micellaneous Power Plant Equipment	641,637	2.90%	18,607	3.21%	20,627	2,020
336	Roads, Railroads & Bridges	1,275	1.30%	17	1.41%	18	1
	Total Marmet Plant	10,561,189	2.96%	312,739	3.66%	386,701	73,962
	NIAGARA						
331	Structures & Improvements	643,402	2.23%	14,348	14.76%	94,983	80,635
332	Reservoirs, Dams & Waterways	6,428,867	6.44%	414,019	10.16%	653,047	239,028
333	Waterwheels, Turbines & Generators	628,317	4.23%	26,578	4.48%	28,141	1,563
334	Accessory Electric Equipment	492,170	6.26%	30,810	14.40%	70,851	40,041
335	Micellaneous Power Plant Equipment	236,941	5.68%	13,458	6.40%	15,156	1,698
	Total Niagara Plant	8,429,697	5.92%	499,213	10.23%	862,178	362,965
	SMITH MOUNTAIN						
331	Structures & Improvements	15,129,256	1.11%	167,935	1.87%	283,563	115,628
332	Reservoirs, Dams & Waterways	26,723,426	0.97%	259,217	0.98%	261,101	1,884
333	Waterwheels, Turbines & Generators	73,463,990	2.70%	1,983,528	3.20%	2,348,577	365,049
334	Accessory Electric Equipment	10,450,047	3.15%	329,176	3.49%	364,715	35,539
335	Micellaneous Power Plant Equipment	9,525,683	3.55%	338,162	3.53%	335,924	-2,238
336	Roads, Railroads & Bridges	1,052,133	0.73%	7,681	0.83%	8,750	1,069
	Total Smith Mountain Plant	136,344,535	2.26%	3,085,699	2.64%	3,602,630	516,931
	WINFIELD						
331	Structures & Improvements	2,754,498	3.02%	83,186	3.94%	108,438	25,252
332	Reservoirs, Dams & Waterways	2,213,073	2.54%	56,212	2.88%	63,638	7,426
333	Waterwheels, Turbines & Generators	4,621,476	3.69%	170,532	4.06%	187,425	16,893
334	Accessory Electric Equipment	261,339	3.17%	8,284	4.12%	10,773	2,489
335	Micellaneous Power Plant Equipment	3,178,347	2.44%	77,552	2.57%	81,771	4,219
336	Roads, Railroads & Bridges	23,567	2.62%	617	2.72%	641	24
	Total Winfield Plant	13,052,300	3.04%	396,383	3.47%	452,686	56,303
	Total Hydraulic Production Plant	**249,626,475**	**2.81%**	**7,024,127**	**3.73%**	**9,310,257**	**2,286,130**

APPALACHIAN POWER COMPANY
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINNG LIFE METHOD
SCHEDULE II - COMPARE DEPRECIATION EXPENSE USING CURRENT AND STUDY RATES
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2017

WV

NO. (1)	TITLE (2)	ORIGINAL COST (3)	CURRENT APPROVED RATE (4)	ANNUAL ACCRUAL (5)	STUDY RATE (6)	STUDY ACCRUAL (7)	DIFFERENCE (DECREASE) (8)
	Other Production Plant						
	CEREDO						
341	Structures & Improvements	1,652,232	1.22%	20,157	1.34%	22,175	2,018
344	Generators	179,404,448	1.17%	2,099,032	1.34%	2,411,908	312,876
345	Accessory Electrical Equip.	18,824,142	1.25%	235,302	1.40%	263,982	28,680
346	Misc. Power Plant Equip.	1,080,430	3.78%	40,840	3.98%	42,969	2,129
	Total	200,961,252	1.19%	2,395,331	1.36%	2,741,034	345,703
	DRESDEN						
341	Structures & Improvements	45,788,946	2.90%	1,327,879	3.32%	1,521,150	193,271
342	Fuel Holders, Producers and Access.	25,974,514	2.92%	758,456	2.90%	753,243	-5,213
344	Generators	302,947,239	2.89%	8,755,175	3.10%	9,381,331	626,156
345	Accessory Electrical Equip.	23,253,887	2.95%	685,990	3.07%	714,738	28,748
346	Misc. Power Plant Equip.	28,457,081	4.32%	1,229,346	3.84%	1,091,748	-137,598
	Total	426,421,667	2.99%	12,756,846	3.16%	13,462,210	705,364
	Total Other Production Plant	**627,382,919**	**2.42%**	**15,152,177**	**2.58%**	**16,203,244**	**1,051,067**
	Total Production Plant	**6,271,239,666**	**2.88%**	**180,393,807**	**3.57%**	**224,160,438**	**43,766,631**
	TRANSMISSION PLANT						
351	Electric Storage Equipment (4)	3,054,157	6.67%	203,712	14.22%	434,247	230,535
352	Structures & Improvements	53,745,705	1.52%	816,935	1.62%	871,011	54,076
353	Station Equipment	1,363,303,699	1.68%	22,903,502	2.37%	32,348,964	9,445,462
354	Towers & Fixtures	472,289,197	1.54%	7,273,254	1.59%	7,499,433	226,179
355	Poles & Fixtures	365,254,244	2.64%	9,642,712	2.71%	9,897,909	255,197
356	OH Conductor & Devices	605,491,610	1.19%	7,205,350	1.53%	9,235,546	2,030,196
357	Underground Conduit	279,063	1.45%	4,046	3.71%	10,349	6,303
358	Underground Conductor	7,362,601	7.23%	532,316	5.24%	385,751	-146,565
	Total Transmission Plant	**2,870,780,276**	**1.69%**	**48,581,827**	**2.11%**	**60,683,210**	**12,101,383**
	DISTRIBUTION PLANT - VA (5)						
361	Structures & Improvements	20,641,688	2.41%	497,465	1.90%	392,273	-105,192
362	Station Equipment	299,858,775	2.45%	7,346,540	2.52%	7,553,621	207,081
364	Poles, Towers, & Fixtures	376,885,792	5.76%	21,708,622	4.77%	17,965,672	-3,742,950
365	Overhead Conductor & Devices	454,010,558	2.89%	13,120,905	3.38%	15,339,873	2,218,968
366	Underground Conduit	63,827,711	1.88%	1,199,961	1.73%	1,104,138	-95,823
367	Underground Conductor	176,447,463	1.51%	2,664,357	2.05%	3,617,162	952,805
368	Line Transformers	355,171,104	4.24%	15,059,255	4.65%	16,506,559	1,447,304
369	Services	174,005,477	3.89%	6,768,813	4.22%	7,338,237	569,424
370	Meters	84,201,217	4.41%	3,713,274	12.43%	10,463,016	6,749,742
371	Installations on Custs. Prem.	35,899,290	13.22%	4,745,886	9.30%	3,337,973	-1,407,913
372	Leased Property on Customers Premises	771	5.70%	44	5.70%	44	0
373	Street Lighting & Signal Sys.	18,688,467	6.00%	1,121,308	8.17%	1,527,603	406,295
	Total Distribution Plant - VA	2,059,638,313	3.78%	77,946,430	4.13%	85,146,171	7,199,741
	DISTRIBUTION PLANT - WV						
361	Structures & Improvements	17,044,918	2.41%	410,783	1.90%	323,920	-86,863
362	Station Equipment	217,442,695	2.45%	5,327,346	2.52%	5,477,511	150,165
363	Energy Storage Equipment (6)	5,402,894	6.67%	360,373	7.38%	398,516	38,143
364	Poles, Towers, & Fixtures	365,925,167	5.76%	21,077,290	4.77%	17,443,193	-3,634,097
365	Overhead Conductor & Devices	412,983,405	2.89%	11,935,220	3.38%	13,953,669	2,018,449
366	Underground Conduit	48,974,647	1.88%	920,723	1.73%	847,199	-73,524
367	Underground Conductor	99,396,168	1.51%	1,500,882	2.05%	2,037,615	536,733
368	Line Transformers	227,926,361	4.24%	9,664,078	4.65%	10,592,866	928,788
369	Services	158,433,513	3.89%	6,163,064	4.22%	6,681,529	518,465
370	Meters (7)	44,209,707	4.41%	1,949,648	12.43%	5,493,589	3,543,941
371	Installations on Custs. Prem.	23,204,627	13.22%	3,067,652	9.30%	2,157,603	-910,049
373	Street Lighting & Signal Sys.	9,540,751	6.00%	572,445	8.17%	779,865	207,420
	Total Distribution Plant - WV	1,630,484,853	3.86%	62,949,504	4.06%	66,187,075	3,237,571
	DISTRIBUTION PLANT - TN						
370	Meters	47,141	4.00%	1,886	1.59%	751	-1,135
	Total Distribution Plant - TN	47,141	4.00%	1,886		751	-1,135
	Total Distribution Plant	**3,690,170,307**	**3.82%**	**140,897,820**	**4.10%**	**151,333,997**	**10,436,177**

APPALACHIAN POWER COMPANY
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINNG LIFE METHOD
SCHEDULE II - COMPARE DEPRECIATION EXPENSE USING CURRENT AND STUDY RATES
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2017

WV

NO. (1)	TITLE (2)	ORIGINAL COST (3)	CURRENT APPROVED RATE (4)	ANNUAL ACCRUAL (5)	STUDY RATE (6)	STUDY ACCRUAL (7)	DIFFERENCE (DECREASE) (8)
GENERAL PLANT							
390	Structures & Improvements	116,542,664	1.25%	1,456,783	1.91%	2,224,741	767,958
391	Office Furniture & Equipment	8,897,328	2.92%	259,802	3.17%	282,185	22,383
392	Transportation Equipment	8,674	3.70%	321	3.40%	295	-26
393	Stores Equipment	1,764,272	1.71%	30,169	1.80%	31,673	1,504
394	Tools Shop & Garage Equipment	32,170,663	2.53%	813,918	2.57%	826,901	12,983
395	Laboratory Equipment	2,830,764	3.83%	108,418	4.01%	113,603	5,185
396	Power Operated Equipment	0	3.90%	0	0.00%	0	0
397	Communication Equipment	43,098,607	5.05%	2,176,480	4.98%	2,145,909	-30,571
398	Miscellaneous Equipment	6,893,105	2.63%	181,289	2.70%	185,992	4,703
	Total General Plant	**212,206,077**	**2.37%**	**5,027,180**	**2.74%**	**5,811,299**	**784,119**
	Total Depreciable Plant	**13,044,396,326**	**2.87%**	**374,900,634**	**3.39%**	**441,988,944**	**67,088,310**

Notes:

1. In May 2015, APCo retired the Philip Sporn Plant (APCo owned Units 1 and 3), Glen Lyn Units 5 and 6, the Kanawha River Plant, Clinch River Unit 3 and the coal related property at Clinch River Units 1&2. Clinch River Units 1&2 were converted to burn natural gas in 2016.

2. Clinch River Units 1 and 2 were converted to burn natural gas in 2016.

3. In April 2016, the Reusens Hydro facility was sold to Eagle Creek Renewable Energy, LLC, an unaffiliated company.

4. Account 351, Electric Storage Equipment - The amount in account 351 represents the Company's investment in a sodium sulphur (NaS) storage battery at its Chemical 138KV Substation.

5. Using West Virginia depreciation rates for Virginia Distribution property for total Company comparison purposes, except for account 372 where West Virginia has no investment. This account uses Virginia's depreciation rate.

6. Account 363 Energy Storage Equipment represents a sodium sulphur (NaS) battery at APCo's WV Balls Gap 138KV Substation.

7. Account 370 Excludes AMI Meters (account 37016) located in Virginia.

APPALACHIAN POWER COMPANY
SCHEDULE III - COMPARISON OF MORTALITY CHARACTERISTICS
DEPRECIATION STUDY AS OF DECEMBER 31, 2017

WV

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
		Existing Rates (a)					Current Study Rates				
		Avg. Service Life	Iowa Curve	Salvage	Cost of Removal	Net Salvage Factor	Avg. Service Life	Iowa Curve	Salvage	Cost of Removal	Net Salvage Factor
TRANSMISSION PLANT											
351	Energy Storage Equipment	15	SQ	5%	5%	0%	15	SQ	5%	5%	0%
352	Structures & Improvements	62	R4.0	5%	15%	-10%	64	R4.0	5%	20%	-15%
353	Station Equipment	45	R1.5	28%	13%	15%	47	R2.0	14%	22%	-8%
354	Towers & Fixtures	68	R3.0	25%	35%	-10%	71	R3.0	0%	15%	-15%
355	Poles & Fixtures	42	R0.5	5%	20%	-15%	42	L1.5	9%	21%	-12%
356	Overhead Conductor & Devices	64	R3.0	30%	18%	12%	67	R4.0	14%	17%	-3%
357	Underground Conduit	50	R2.0	0%	0%	0%	45	S5.0	0%	0%	0%
358	Underground Conductor and Devices	20	L4.0	0%	0%	0%	24	L3.5	0%	0%	0%
DISTRIBUTION PLANT											
361	Structures & Improvements	50	R3.0	4%	16%	-12%	55	R3.0	4%	16%	-12%
362	Station Equipment	40	R1.0	7%	9%	-2%	45	R1.0	6%	22%	-16%
363	Energy Storage Equipment	15	SQ	3%	3%	0%	15	SQ	3%	3%	0%
364	Poles, Towers, & Fixtures	28	R0.5	17%	77%	-60%	33	R0.5	14%	81%	-67%
365	Overhead Conductor & Devices	35	L0.0	24%	32%	-8%	35	R0.5	19%	35%	-16%
366	Underground Conduit	50	S4.0	0%	0%	0%	55	R4.0	0%	0%	0%
367	Underground Conductor	55	R0.5	0%	0%	0%	48	R1.5	0%	0%	0%
368	Line Transformers	27	R0.5	9%	24%	-15%	27	R0.5	8%	28%	-20%
369	Services	30	R0.5	1%	22%	-21%	30	R0.5	1%	27%	-26%
370	Meters	25	S6.0	10%	20%	-10%	15	S6.0	10%	20%	-10%
371	Installations on Custs. Prem.	10	R0.5	3%	23%	-20%	12	R0.5	1%	23%	-22%
372	Leased Property on Custs. Prem.	25	L3.0	0%	0%	0%	25	L3.0	0%	0%	0%
373	Street Lighting & Signal Sys.	20	R0.5	9%	16%	-7%	20	R0.5	3%	34%	-31%
GENERAL PLANT											
390	Structures & Improvements	42	R2.5	36%	11%	25%	42	R2.5	24%	12%	12%
391	Office Furniture & Equipment	30	SQ	0%	0%	0%	30	SQ	0%	0%	0%
392	Transportation Equipment	27	SQ	0%	0%	0%	27	SQ	0%	0%	0%
393	Stores Equipment	55	SQ	0%	0%	0%	55	SQ	0%	0%	0%
394	Tools Shop & Garage Equipment	43	SQ	0%	10%	-10%	43	SQ	0%	10%	-10%
395	Laboratory Equipment	37	SQ	0%	0%	0%	37	SQ	0%	0%	0%
396	Power Operated Equipment	25	SQ	0%	0%	0%	25	SQ	0%	0%	0%
397	Communication Equipment	24	SQ	0%	1%	-1%	24	SQ	0%	3%	-3%
398	Miscellaneous Equipment	35	SQ	0%	0%	0%	35	SQ	0%	0%	0%

N/A = Not Available

(a) Existing rates were set in the 2015 order in Case No. 14-1151-E-D.

APPALACHIAN POWER COMPANY
SCHEDULE IV - ESTIMATED GENERATION PLANT RETIREMENT DATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2017

Plant	Capacity (MW)	Fuel	Year Installed	Year Retired	Life Span (Years)
Steam Production Plant					
Mountaineer					
Unit 1	1,300	Coal	1980	2040	60
Amos					
Unit 1	800	Coal	1971	2040	69
Unit 2	800	Coal	1972	2040	68
Unit 3	1,300	Coal	1973	2040	67
Clinch River (see Note 1)					
Unit 1	235	Gas	1958	2025	67
Unit 2	235	Gas	1958	2025	67
Hydraulic Production Plant (see Note 2)					
Buck	8.5	Hydro	1912	2024	112
Byllesby	21.6	Hydro	1912	2024	112
Claytor	75.0	Hydro	1939	2041	102
Niagara	2.4	Hydro	1906	2024	118
Leesville	50.0	Hydro	1964	2040	76
London	14.4	Hydro	1935	2044	109
Marmet	14.4	Hydro	1935	2044	109
Winfield	14.8	Hydro	1938	2044	106
Smith Mountain	586.0	Hydro	1965	2040	75
Other Production Plant					
Ceredo	505.0	Gas	2001	2041	40
Dresden	580.0	Gas	2012	2047	35

Note 1: In May 2015, APCo retired the Philip Sporn Plant (APCo owned Units 1 and 3), Glen Lyn Units 5 and 6, the Kanawha River Plant, Clinch River Unit 3 and the coal related property at Clinch River Units 1&2. Clinch River Units 1&2 were converted to burn natural gas in 2016.

Note 2: In April 2017, the Reusens Hydro facility was sold to Eagle Creek Renewable Energy, LLC,

WHEELING POWER COMPANY
SCHEDULE V - CALCULATION OF DEPRECIATION RATES BY THE REMAINNG LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2017

ACCT NO (I)	ACCOUNT TITLE (II)	ORIGINAL COST (III)	NET SALVG. RATIO (IV)	TOTAL TO BE RECOVERED (V)	THEORETICAL RESERVE (VI)	ACCUMULATED DEPRECIATION (VII)	REMAINING AMOUNT (VIII)	AVG. REMAIN LIFE (IX)	ANNUAL ACCRUAL (X)	DEPR. RATE (XI)
STEAM PRODUCTION PLANT - Mitchell Plant (1)										
311	Structures & Improvements	53,332,086	1.02	54,398,728	24,422,231	20,864,545	33,534,183	21.75	1,541,802	2.89%
312	Boiler Plant Equipment	856,061,124	1.02	873,182,346	337,730,576	307,135,233	566,047,113	20.69	27,358,488	3.20%
312	Boiler Plant Equip. SCR Catalyst (2)	8,222,121	1.02	8,386,563	5,042,901	5,294,205	3,092,358	11.00	762,415	9.27%
314	Turbogenerator Units	54,384,766	1.02	55,472,461	32,380,463	34,828,283	20,644,178	20.56	1,004,094	1.85%
315	Accessory Electrical Equip.	25,083,488	1.02	25,585,158	13,069,940	12,063,523	13,521,635	22.11	611,562	2.44%
316	Misc. Power Plant Equip.	8,517,531	1.02	8,687,882	4,052,314	3,830,693	4,857,189	21.30	228,037	2.68%
	Total Steam Production Plant	**1,005,601,116**	**1.02**	**1,025,713,138**	**416,698,425**	**384,016,482**	**641,696,656**	**20.37**	**31,506,397**	**3.13%**
TRANSMISSION PLANT										
352	Structures & Improvements	839,943	1.15	965,934	454,407	638,477	327,457	33.89	9,662	1.15%
353	Station Equipment	67,623,062	1.08	73,032,907	15,225,348	17,074,146	55,958,761	37.20	1,504,268	2.22%
354	Towers & Fixtures	5,656,550	1.15	6,505,033	2,942,271	683,650	5,821,383	38.89	149,688	2.65%
355	Poles & Fixtures	44,047,464	1.12	49,333,160	6,240,669	10,343,516	38,989,644	36.69	1,062,678	2.41%
356	OH Conductor & Devices	21,841,377	1.03	22,496,618	4,956,601	7,429,154	15,067,464	52.24	288,428	1.32%
357	Underground Conduit	10,982	1.00	10,982	9,560	4,619	6,363	5.83	1,091	9.94%
358	Underground Conductor	76,937	1.00	76,937	65,441	38,322	38,615	3.59	10,756	13.98%
	Total Transmission Plant	**140,096,315**	**1.09**	**152,421,571**	**29,894,297**	**36,211,884**	**116,209,687**	**38.40**	**3,026,572**	**2.16%**
DISTRIBUTION PLANT										
361	Structures & Improvements	644,230	1.12	721,538	344,344	515,518	206,020	28.75	7,166	1.11%
362	Station Equipment	28,009,517	1.16	32,491,040	7,189,244	10,659,322	21,831,718	35.04	623,051	2.22%
364	Poles, Towers, & Fixtures	37,275,983	1.67	62,250,892	15,317,840	13,296,385	48,954,507	24.88	1,967,625	5.28%
365	Overhead Conductor & Devices	32,056,624	1.16	37,185,684	8,558,711	7,595,476	29,590,208	26.94	1,098,374	3.43%
366	Underground Conduit	14,886,603	1.00	14,886,603	3,070,812	2,501,179	12,385,424	43.65	283,744	1.91%
367	Underground Conductor	17,682,304	1.00	17,682,304	2,997,894	3,710,674	13,971,630	39.86	350,518	1.98%
368	Line Transformers	24,936,196	1.20	29,923,435	8,026,995	6,925,233	22,998,202	19.76	1,163,877	4.67%
369	Services	13,943,662	1.26	17,569,014	5,229,643	4,090,497	13,478,517	21.07	639,702	4.59%
370	Meters	4,889,992	1.10	5,378,991	1,385,627	1,582,855	3,796,136	11.14	340,766	6.97%
371	Installations on Custs. Prem.	1,870,882	1.22	2,282,476	1,216,196	874,724	1,407,752	5.61	250,936	13.41%
373	Street Lighting & Signal Sys.	1,597,508	1.31	2,092,735	1,078,639	449,995	1,642,740	9.69	169,529	10.61%
	Total Distribution Plant	**177,793,501**	**1.25**	**222,464,712**	**54,415,945**	**52,201,858**	**170,262,854**	**24.69**	**6,895,288**	**3.88%**
GENERAL PLANT										
390	Structures & Improvements	3,123,534	0.88	2,748,710	1,011,958	1,855,394	893,316	26.54	33,659	1.08%
391	Office Furniture & Equipment	49,011	1.00	49,011	21,787	31,624	17,387	16.66	1,044	2.13%
393	Stores Equipment	40,912	1.00	40,912	1,257	2,181	38,731	53.31	727	1.78%
394	Tools Shop & Garage Equipment	605,457	1.10	666,003	135,414	324,260	341,743	34.26	9,975	1.65%
397	Communication Equipment	1,351,392	1.03	1,391,934	660,964	525,264	866,670	12.60	68,783	5.09%
398	Miscellaneous Equipment	191,041	1.00	191,041	52,984	57,708	133,333	25.29	5,272	2.76%
	Total General Plant	**5,361,347**	**0.95**	**5,087,610**	**1,884,364**	**2,796,431**	**2,291,179**	**19.18**	**119,460**	**2.23%**
Total Depreciable Plant		**1,328,852,279**	**1.06**	**1,405,687,031**	**502,893,031**	**475,226,655**	**930,460,376**	**22.39**	**41,547,717**	**3.13%**

Notes:

1. **WPCo's 50% share of Mitchell Plant's original cost and accumulated depreciation.**
2. **According to AEPSC Air Emissions Control, the average life for SCR catalyst at Mitchell is 11 years. The catalyst depreciation rate was set using a whole life type calculation (total to be recovered/average service life).**

WHEELING POWER COMPANY
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINNG LIFE METHOD
SCHEDULE VI - COMPARE DEPRECIATION EXPENSE USING CURRENT AND STUDY RATES
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2017

NO. (1)	TITLE (2)	ORIGINAL COST (3)	CURRENT APPROVED RATE (4)	CURRENT ANNUAL ACCRUAL (5)	STUDY RATE (6)	STUDY ACCRUAL (7)	DIFFERENCE (DECREASE) (8)
Steam Production Plant							
	MITCHELL PLANT (1)						
311	Structures & Improvements	53,332,086	2.46%	1,311,969	2.89%	1,541,802	229,833
312	Boiler Plant Equipment	856,061,124	2.84%	24,312,136	3.20%	27,358,488	3,046,352
312	Boiler Plant Equip. SCR Catalyst (2)	8,222,121	12.50%	1,027,765	9.27%	762,415	-265,350
314	Turbogenerator Units	54,384,766	1.55%	842,964	1.85%	1,004,094	161,130
315	Accessory Electrical Equipment	25,083,488	1.37%	343,644	2.44%	611,562	267,918
316	Misc. Power Plant Equip.	8,517,531	2.49%	212,087	2.68%	228,037	15,950
	Total Steam Production Plant	**1,005,601,116**	**2.79%**	**28,050,565**	**3.13%**	**31,506,398**	**3,455,833**
TRANSMISSION PLANT							
352	Structures & Improvements	839,943	0.69%	5,796	1.15%	9,662	3,866
353	Station Equipment	67,623,062	1.70%	1,149,592	2.22%	1,504,268	354,676
354	Towers & Fixtures	5,656,550	0.04%	2,263	2.65%	149,688	147,425
355	Poles & Fixtures	44,047,464	2.65%	1,167,258	2.41%	1,062,678	-104,580
356	OH Conductor & Devices	21,841,377	1.12%	244,623	1.32%	288,428	43,805
357	Underground Conduit	10,982	2.00%	220	9.94%	1,091	871
358	Underground Conductor	76,937	5.00%	3,847	13.98%	10,756	6,909
	Total Transmission Plant	**140,096,315**	**1.84%**	**2,573,599**	**2.16%**	**3,026,571**	**452,972**
DISTRIBUTION PLANT							
361	Structures & Improvements	644,230	2.31%	14,882	1.11%	7,166	-7,716
362	Station Equipment	28,009,517	2.57%	719,845	2.22%	623,051	-96,794
364	Poles, Towers, & Fixtures	37,275,983	5.77%	2,150,824	5.28%	1,967,625	-183,199
365	Overhead Conductor & Devices	32,056,624	3.10%	993,755	3.43%	1,098,374	104,619
366	Underground Conduit	14,886,603	2.02%	300,709	1.91%	283,744	-16,965
367	Underground Conductor	17,682,304	1.82%	321,818	1.98%	350,518	28,700
368	Line Transformers	24,936,196	4.29%	1,069,763	4.67%	1,163,877	94,114
369	Services	13,943,662	4.07%	567,507	4.59%	639,702	72,195
370	Meters	4,889,992	4.41%	215,649	6.97%	340,766	125,117
371	Installations on Custs. Prem.	1,870,882	12.37%	231,428	13.41%	250,936	19,508
373	Street Lighting & Signal Sys.	1,597,508	5.47%	87,384	10.61%	169,529	82,145
	Total Distribution Plant	**177,793,501**	**3.75%**	**6,673,564**	**3.88%**	**6,895,288**	**221,724**

WHEELING POWER COMPANY
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINNG LIFE METHOD
SCHEDULE VI - COMPARE DEPRECIATION EXPENSE USING CURRENT AND STUDY RATES
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2017

NO. (1)	TITLE (2)	ORIGINAL COST (3)	CURRENT APPROVED RATE (4)	CURRENT ANNUAL ACCRUAL (5)	STUDY RATE (6)	STUDY ACCRUAL (7)	DIFFERENCE (DECREASE) (8)
GENERAL PLANT							
390	Structures & Improvements	3,123,534	0.89%	27,799	1.08%	33,659	5,860
391	Office Furniture & Equipment	49,011	1.91%	936	2.13%	1,044	108
393	Stores Equipment	40,912	1.74%	712	1.78%	727	15
394	Tools Shop & Garage Equipment	605,457	2.03%	12,291	1.65%	9,975	-2,316
397	Communication Equipment	1,351,392	2.37%	32,028	5.09%	68,783	36,755
398	Miscellaneous Equipment	191,041	2.10%	4,012	2.76%	5,272	1,260
	Total General Plant	**5,361,347**	**1.45%**	**77,778**	**2.23%**	**119,460**	**41,682**
	Total Depreciable Plant	**1,328,852,279**	**2.81%**	**37,375,506**	**3.13%**	**41,547,717**	**4,172,211**

Notes:

1. WPCo's 50% interest in the Mitchell Plant at December 31, 2017.

2. According to AEPSC Air Emissions Control, the average life for SCR catalyst at Mitchell is 11 years. The catalyst depreciation rate was set using a whole life type calculation (total to be recovered/average service life).

WHEELING POWER COMPANY
SCHEDULE VII - COMPARISON OF MORTALITY CHARACTERISTICS
DEPRECIATION STUDY AS OF DECEMBER 31, 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
		Existing Rates					Current Study Rates (a)				
		Avg. Service Life	Iowa Curve	Salvage	Cost of Removal	Net Salvage Factor	Avg. Service Life	Iowa Curve	Salvage	Cost of Removal	Net Salvage Factor
TRANSMISSION PLANT											
352	Structures & Improvements	62	R4.0	5%	15%	-10%	64	R4.0	5%	20%	-15%
353	Station Equipment	45	R1.5	28%	13%	15%	47	R2.0	14%	22%	-8%
354	Towers & Fixtures	68	R3.0	25%	35%	-10%	71	R3.0	0%	15%	-15%
355	Poles & Fixtures	42	R0.5	5%	20%	-15%	42	L1.5	9%	21%	-12%
356	Overhead Conductor & Devices	64	R3.0	30%	18%	12%	67	R4.0	14%	17%	-3%
357	Underground Conduit	50	R2.0	0%	0%	0%	45	S5.0	0%	0%	0%
358	Underground Conductor and Devices	20	L4.0	0%	0%	0%	24	L3.5	0%	0%	0%
DISTRIBUTION PLANT											
361	Structures & Improvements	50	R3.0	4%	16%	-12%	55	R3.0	4%	16%	-12%
362	Station Equipment	40	R1.0	7%	9%	-2%	45	R1.0	6%	22%	-16%
364	Poles, Towers, & Fixtures	28	R0.5	17%	77%	-60%	33	R0.5	14%	81%	-67%
365	Overhead Conductor & Devices	35	L0.0	24%	32%	-8%	35	R0.5	19%	35%	-16%
366	Underground Conduit	50	S4.0	0%	0%	0%	55	R4.0	0%	0%	0%
367	Underground Conductor	55	R0.5	0%	0%	0%	48	R1.5	0%	0%	0%
368	Line Transformers	27	R0.5	9%	24%	-15%	27	R0.5	8%	28%	-20%
369	Services	30	R0.5	1%	22%	-21%	30	R0.5	1%	27%	-26%
370	Meters	25	S6.0	10%	20%	-10%	15	S6.0	10%	20%	-10%
371	Installations on Custs. Prem.	10	R0.5	3%	23%	-20%	12	R0.5	1%	23%	-22%
373	Street Lighting & Signal Sys.	20	R0.5	9%	16%	-7%	20	R0.5	3%	34%	-31%
GENERAL PLANT											
390	Structures & Improvements	42	R2.5	36%	11%	25%	42	R2.5	24%	12%	12%
391	Office Furniture & Equipment	30	SQ	0%	0%	0%	30	SQ	0%	0%	0%
393	Stores Equipment	55	SQ	0%	0%	0%	55	SQ	0%	0%	0%
394	Tools Shop & Garage Equipment	43	SQ	0%	10%	-10%	43	SQ	0%	10%	-10%
397	Communication Equipment	24	SQ	0%	1%	-1%	24	SQ	0%	3%	-3%
398	Miscellaneous Equipment	35	SQ	0%	0%	0%	35	SQ	0%	0%	0%

N/A = Not Available

(a) Used mortality statistics from APCo's Depreciation Study dated December 31, 2017

WHEELING POWER COMPANY
SCHEDULE VIII - MITCHELL PLANT RETIREMENT DATE
DEPRECIATION STUDY AS OF DECEMBER 31, 2017

Plant	Capacity (MW)	Fuel	Year Installed	Year Retired	Life Span (Years)
Steam Production Plant					
Mitchell Plant (see Note 1)					
Unit 1	770	Coal	1971	2040	69
Unit 2	790	Coal	1971	2040	69

Note 1: The Mitchell Plant is co-owned by Wheeling Power Company and Kentucky Power Company with each company owning a 50% undivided share.

DATA REQUEST

AG 1-34 Reference Figure ES-6. Confirm that under the Preferred Plan, 21% of KPCo's 2034 energy mix would be based on market power.

RESPONSE

Confirmed.

Witness: John F. Torpey

DATA REQUEST

AG 1-35 Reference Figure ES-8. In light of the fact that KPCo's customer count, and its retail residential sales will be decreasing throughout the 15-year planning period, explain why the load obligation remains relatively unchanged.

RESPONSE

Load additions in the industrial sector essentially offset load loss in the residential and commercial sectors. Thus, resulting in load being relatively unchanged.

Witness: John F. Torpey

DATA REQUEST

AG 1-36 Reference IRP § 1.5, Table 2. Explain whether the prices identified under the column for PRB coal include transportation costs.

RESPONSE

The values shown in the referenced table are FOB mine prices and do not include transportation.

Witness: John F. Torpey

DATA REQUEST

AG 1-37 Reference IRP § 1.5, the discussion regarding CHP referenced in the 2016 IRP. Explain why CHP is not included in the instant IRP.

RESPONSE

There are currently no KPCo customers interested in exploring this opportunity. See Section 4.7. Additionally, the Company included a CHP resource option in the modeling; however, it was not selected.

Witness: John F. Torpey

DATA REQUEST

AG 1-38 Reference IRP § 1.5. Explain why battery storage was excluded in the instant IRP.

RESPONSE

A Battery Storage resource was available in the model, it was not selected in the modeling results and thus is not in the Company's Preferred Plan for this IRP.

Witness: John F. Torpey

DATA REQUEST

AG 1-39 Explain whether the load forecast takes into consideration possible new load from Braidy Industries. If so, explain further whether the potential Braidy Industries plant is reflected as one of the 23 potential economic development projects discussed in IRP § 2.12.5 (4).

RESPONSE

Yes. The load reflects impacts of the potential load addition for Braidy Industries. The estimated impacts of economic development projects includes Braidy Industries.

Witness: John F. Torpey

DATA REQUEST

AG 1-40 Explain whether the Company is aware of any potential changes to the load forecast as a result of the Coronavirus outbreak. Include in your discussion whether KPCo's service company affiliate, and/or PJM have provided any guidance in this regard. If so, explain.

RESPONSE

Yes. The Company is aware of potential impacts of the COVID-19 pandemic and related government orders on Kentucky Power's load forecast. As part of the normal planning process, AEP's Economic Forecasting group recently computed the estimated impacts of the COVID-19 pandemic and related government orders on Kentucky Power's load forecast using updated economic forecast data from Moody's Analytics. Also, the PJM load forecasting group recently described a similar update based on Moody's new economic forecast in the May 5, 2020 Load Analysis Subcommittee Meeting.
Also see the Company's response to KPSC 1-10 in this proceeding.

Witness: John F. Torpey

Kentucky Power Company
KPSC Case No. 2019-00443
Attorney General's First Set of Data Requests
Dated April 9, 2020

DATA REQUEST

AG 1-41 Reference IRP § 3.2. Provide a discussion on what portions of the Big Sandy 1 unit were placed into service in 2016, and what portions were placed into service at an earlier date.

RESPONSE

The portions of Big Sandy Unit 1 placed in service in 2016 were the equipment necessary to accept the delivery of natural gas to the site and to consume that natural gas in the boiler. As discussed in the Direct testimony of Company witness Walton in Case No. 2013-00430 before this Commission, these included:

- Modifications to the steam generator (boiler) pressure part circuitry;
- Replacement of the existing coal combustion burners with natural gas burners;
- Installation of new gas piping and valve racks;
- Installation of new gas burning ignitors;
- Associated electrical, instrumentation and burner management control system modifications;
- Continuous Emissions Monitoring System modifications;
- Installation of new fuel gas check metering, heater, and pressure regulating station; and
- Installation of (2) flame scanner cooling air blowers.

Big Sandy 1 entered service in 1963. The major equipment placed in service at that time for the unit to operate as a coal-fired power plant includes, but is not limited to, the following: coal handling equipment, boiler, steam turbines, electrostatic precipitator, stack, solid waste handling systems, and cooling tower.

Witness: John F. Torpey

DATA REQUEST

AG 1-42 Reference IRP § 3.2, wherein it is stated that KPCo is currently negotiating the addition of 20 MW of solar generation. Explain whether:
a. this facility would be company-owned, or through a PPA; and
b. whether the proposed facility would be located inside or outside of Kentucky.

RESPONSE

Negotiations associated with the 20 MW of solar generation referenced in IRP §3.2 have ceased due to project permitting issues. The 20 MW opportunity was the result of a competitive request for proposals (RFP) issued by the Company on October 17, 2018 (www.kentuckypower.com/rfp).

a. The RFP solicited proposals that would be Company-owned, via a Purchase and Sale Agreement for purchase of 100% of the equity interest of a project's limited liability company at the completion of the project's construction and commissioning.

b. The RFP solicited proposals for the purchase of solar energy resources in the Kentucky Power Company's service territory.

Witness: Brian K. West

Witness: John F. Torpey

Kentucky Power Company
KPSC Case No. 2019-00443
Attorney General's First Set of Data Requests
Dated April 9, 2020

DATA REQUEST

AG 1-43 Reference IRP § 3.2. Confirm that the anticipated cancellation of the Rockport UPA includes KPCo's share of power from both Rockport units.

RESPONSE

Confirmed.

Witness: Brian K. West

Witness: John F. Torpey

Kentucky Power Company
KPSC Case No. 2019-00443
Attorney General's First Set of Data Requests
Dated April 9, 2020

DATA REQUEST

AG 1-44 Explain whether KPCo's anticipated non-renewal of the Rockport UPA will terminate KPCo's share of environmental and all other costs arising from the operation of the Rockport units. If not, explain why not.

RESPONSE

The IRP assumes that the Rockport UPA will not be renewed. If the Rockport UPA is not renewed, Kentucky Power will no longer incur costs arising from the operation of the Rockport units when the UPA terminates.

Witness: Brian K. West

Witness: John F. Torpey

DATA REQUEST

AG 1-45 Explain whether KPCo's anticipated non-renewal of the Rockport UPA will result in KPCo accruing any additional air pollution credits. If so, explain whether those credits could be used at the Mitchell plant.

RESPONSE

The non-renewal of the Rockport UPA is not expected to result in KPCo accruing any additional air pollution credits.

Witness: Brian K. West

Witness: John F. Torpey

DATA REQUEST

AG 1-46 Provide a discussion on the projected costs KPCo could incur in complying with the CCR and ELG rules at the Rockport and Mitchell stations.

RESPONSE

See the Company's response to AG 1-10. For a discussion of the rules, please see Section 3.3 - Environmental Issues and Implications - of the Company's IRP filed with the Commission on December 20, 2019 in this Case.

Witness: John F. Torpey

DATA REQUEST

AG 1-47 Reference IRP § 4.4.3.3, which discusses a bring your own thermostat program. Explain whether customers participating in such a program would be required to have a smart meter in order for their devices to communicate with the Company.

RESPONSE

For this IRP and this resource, it is assumed that the customer would not be required to have a "smart meter."

Witness: John F. Torpey

DATA REQUEST

AG 1-48 Reference IRP § 4.5.6.2, regarding wind power. Explain whether the modeling was based solely on self-build resources, or whether it included PPAs.

a. Explain whether the wind resources would be located within Kentucky, or outside of its borders.

b. Explain whether the modelling took into consideration the costs of new or modified transmission facilities necessary to transmit the power into and through KPCo's service territory. Also, identify any such transmission additions or modifications that would have to be made, together with price projections.

c. Confirm the statement that ". . . wind energy's life-cycle cost ($/MWh), excluding subsidies, is currently higher than the marginal (avoided) cost of energy, in spite of its negligible operating costs."

d. Explain whether the company is aware of any wind resources in the eastern U.S. carrying capacity factors of 37% and 35%, such as those associated with Tranches A and B, respectively. Given that KPCo assumes wind resources to have a PJM capacity value equal to 12.3% of nameplate rating, explain whether it would be more accurate to rely upon the PJM capacity value.

e. Reference Figure 31. Explain whether the curve for "build costs" refers to self-build by KPCo (or an AEP affiliate) itself.

f. Reference the following statement: "This cap is based on the DOE's Wind Vision Report 18 which suggests from numerous transmission studies that transmission grids should be able to support 20% to 30% of intermittent resources in the 2020 to 2030 timeframe." Explain whether KPCo's transmission grid would be able to support 20% to 30% of intermittent resources in the 2020-2030 timeframe. Include in your discussion any potential congestion charges.

(i) Provide all studies pertaining to the ability of KPCo's grid to provide the cited support.

(ii) If KPCo's grid would require modifications and/or new facilities, provide a detailed summary together with cost projections.

RESPONSE

For this IRP, the wind resources are discussed in Section 4.5.6.2 and are assumed to be self-build or Company owned resources.

a. Wind resources included in the model for this IRP are considered a PJM resource. The specific location of the wind resources identified in the Company's Preferred Plan are not known at this time; however, the performance characteristics of the wind resources included in this IRP are generally aligned with PJM-interconnected wind resources within the state of Indiana.

b. All new resources in this IRP are generic and costs include transmission interconnection costs; however, since resources within IRP are not location specific, additional transmission costs were not available or assumed. During a resource acquisition analysis each resource's evaluation will include its forecasted cost of delivery to the Company.

c. Please refer to Figure 31 and Figure 22 for a comparison of modeled annual LCOE's for wind resources and market prices. On-Peak energy prices remain lower than wind resources (even with PTC subsidies) throughout the planning period.

d. Yes, a contracted resource with an AEP affiliate operating in PJM is operating at capacity factors at or above those used in this IRP.

With respect to the inquiry if the PJM capacity value would be more accurate, the Company respectfully believes the question is premised upon a misunderstanding between Capacity Value and Capacity Factor. In fact, the Company uses both values in the model to solve for meeting capacity reserve margins and peak loads.

Capacity Factor is different than Capacity Value. The Capacity Value (MW) is established by PJM and is the amount of generating capacity expressed in MW that a resource can contribute during peak hours and which can be offered as unforced capacity. Capacity Factor, in contrast, is a measurement of the actual electrical energy output (MWh) over a given period of time to the maximum possible electrical energy output over that period.

e. Yes, for this IRP, this refers to self-build or owned resources.

f i-ii. The Company has not performed any studies related to potential future resources included in the IRP. Kentucky Power performs transmission planning consistent with PJM requirements. As part of that process, generation projects, including renewables, are placed into the PJM interconnection queue and become part of future market efficiency studies. Planning processes in PJM then take into account transmission needs associated with the location and characteristics of a specific asset.

Witness: John F. Torpey

DATA REQUEST

AG 1-49 Reference IRP § 4.5.6.3. Explain whether KPCo's review of potential hydro resources analyzed the potential for PPAs from existing hydro resources. Include in your response whether KPCo considered PPAs with Canadian-based hydro resources.

RESPONSE

Hydro PPAs were not specifically analyzed as part of the IRP; however, as part of a resource acquisition process the Company may consider competitive proposals from entities such as Canadian hydro power resources.

Witness: John F. Torpey

DATA REQUEST

AG 1-50 Reference IRP § 5.1. Explain whether Plexos® takes into consideration the following with regard to KPCo's generating units: PJM dispatch rate, number of hours of any self-scheduling, and off-system sales.

RESPONSE

The PJM market price/dispatch rate is the price Plexos takes into consideration when it dispatches its generating units. While PLEXOS does allow for modeling self-scheduling practices, none were applied in Kentucky Power scenarios. All Kentucky Power generating unit energy is considered to be sold into the PJM energy market. The Kentucky Power load is met by PJM market purchases. The difference between sales and purchases may be considered "off-system sales."

Witness: John F. Torpey

DATA REQUEST

AG 1-51 Reference Figure 32. Explain whether a lower-end combined cycle unit, in the range of 200 – 350 MW output, would compare in terms of cost effectiveness to the selected resources for the base and low-band cases. Include in your discussion the year in which it would become cost-effective.
a. Provide the same analysis with regard to a higher-end combined cycle unit, in the range of 1000 – 16000 MW, in which KPCo owns a 25% share. Include in your discussion the year in which it would become cost-effective.

RESPONSE

The Company cannot provide a definitive answer to this question without completing new and/or additional work; however, the Company offers the following comment. Generally, when the Company considers estimates and operational characteristics for smaller output (nameplate MW capacity) combined cycle resources, often their levelized cost is higher than what was modeled in this IRP. This effect is evident in Exhibit D of the IRP, comparing the smaller 1X1 combined cycle configuration to the larger 2X1 configurations. Furthermore, because the optimization model was allowed to select a 25% share (400 MW) of a highly efficient and low cost 2X1 natural gas combined cycle resource but did not, the manual inclusion of a less efficient and higher cost combined-cycle resource would increase the cost of each plan, or in other words is not cost effective.

a. Refer to IRP Exhibit E1 where the resource portfolios for all of the scenarios the Company considered for this IRP are presented. The first row in each table represents the natural gas resources included in each scenario. The "higher-end combined cycle unit", is represented by the 401MW amount and appears in the High Load and Case 8 portfolios. In the High Load scenario the combined cycle unit is cost effective in 2031. In Case 8 the combined cycle unit was forced into the portfolio in 2024. The cost for Case 8 is higher than for the Preferred Plan or the Base Optimized plans as shown in IRP Exhibit E2.

Witness: John F. Torpey

DATA REQUEST

AG 1-52 Reference IRP § 5.2.2.4, Stakeholder Optimization Scenarios, the following statement: "The analysis did show that utilizing STMP through 2024 was the least costly of the stakeholder scenarios over the 15-year planning period; however, over the 30-year study period, the "Renewable Only" plan is the least costly. Note also, that the CC only and CT only scenarios are similar to Cases 7 and 8 described in the IRP Optimization Scenarios section 5.2.2.3 except that the Stakeholder cases exclude any renewable or DSM resources. The costs for these two stakeholder plans ultimately are driven higher than the IRP Optimization Scenarios including the CC and CT due to the exclusion of renewable and DSM resources."

a. Explain whether KPCo analyzed a scenario of a smaller-sized CC that would also include renewable and DSM resources.

RESPONSE

A smaller sized CC was not included as a model resource in this IRP.

a. The scenario described was not modeled.

Witness: John F. Torpey

DATA REQUEST

AG 1-53 Reference Table 17 and Figure 39, regarding the Preferred Plan. Confirm that from 2022-2034, in the row “Capacity Reserves with New Additions,” the capacity surplus would range only from 11-34 MW.

RESPONSE

From 2022 through 2034, the Capacity Reserves (MW) with new additions in the Preferred Plan range from a low of 1MW (2032-2034) to a high of 34 MW (in 2030). Note that this capacity reserve is above the PJM required installed reserve margin.

Witness: John F. Torpey

DATA REQUEST

AG 1-54 Given the Preferred Plan's heavy reliance on renewables, explain how KPCo plans to address reliability given the inherent intermittency associated with renewables.

RESPONSE

Within this IRP, the Company relied on PJM's development of the Effective Load Carrying Capacity (ELCC) for both wind and solar resources this provides a consistent way to assess the capacity value of resources. Kentucky Power modeling utilizes this value as an input to its modeling to select appropriate amounts of renewable resources that will meet PJM reserve capacity requirements. The Company recognizes the intermittent nature of these resources.

Witness: John F. Torpey

Kentucky Power Company
KPSC Case No. 2019-00443
Attorney General's First Set of Data Requests
Dated April 9, 2020

DATA REQUEST

AG 1-55 Reference the "Report of Renewable Power Option Rider Activity in 2019," filed on March 31, 2020 in the post-case documents to Case No. 2017-00179. Given that no KPCo customers participated in Rider R.P.O. in 2019, explain whether the Company still believes it is realistic to expect that within 10 years, KPCo customers will acquire 9 MW of distributed power (solar) generation.

RESPONSE

As described in Section 4.4.3.4 of the IRP, the estimates utilized in this IRP are based on projections provided by PJM. As the adoption rate of rooftop solar changes over time the Company may modify this assumption.

Witness: Ranie K. Wohnhas

Witness: John F. Torpey

DATA REQUEST

AG 1-56 Explain whether KPCo utilizes beneficial reuse of coal ash and coal combustion byproducts.
a. If so, explain how this beneficial reuse occurs and the benefits KPCo's ratepayers receive.
b. In addition to any current reuse, explain if KPCo has pursued any potential reuse opportunities, and if so, provide the details of those opportunities.
c. If KPCo has not pursued any reuse opportunities, explain why KPCo has not done so.

RESPONSE

Yes, Kentucky Power utilizes the beneficial reuse of the coal ash and coal combustion byproducts.

a. Gypsum produced from the Flue Gas Desulfurization System at the Mitchell Plant is sold through a long-term contract, which is in effect through 2032, to a neighboring wallboard manufacturer for the production of sheet rock. Dry Fly Ash from the Mitchell Plant is marketed through a third party marketer into various markets supporting encapsulated beneficial uses. Kentucky Power ratepayers benefits include reduced landfill cost, including reduced plant O&M for disposal activities associated with handling the material. Any credit received by Kentucky Power is recorded in accounts 5010012 (Ash Sales) and 5010028 (Gypsum Sales) and offsets fuel costs.

b. The plant is currently looking into ways to increase the marketability of its Fly Ash. By increasingly managing the carry-through of material from the precipitators, Kentucky Power will be able to market a higher percentage of Fly Ash.

c. Not applicable.

Witness: John F. Torpey

VERIFICATION

The undersigned, John F. Torpey, being duly sworn, deposes and says he is the Managing Director of Resource Planning and Operation Analysis for the 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.

John F Torpey
____
John F. Torpey

State of Indiana	)	
	)	Case No. 2019-00443
County of Allen	)	

Subscribed and sworn before me, a Notary Public, by John F. Torpey this ___19___ day of May, 2020.

Regiana M. Sistevaris

Digitally signed by Regiana M. Sistevaris
Date: 2020.05.19 15:24:02 -04'00'
____
Notary Public, Regiana Maria Sistevaris

My Commission Expires ___January 17, 2023___

VERIFICATION

The undersigned, Brian K. West, being duly sworn, deposes and says he is the Director of Regulatory Services for Kentucky Power, 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.

Brian K. West

State of Indiana)
) Case No. 2019-00443
County of Allen)

Subscribed and sworn before me, a Notary Public, by Brian K. West this 19 day of May, 2020.

Regiana M. Sistevaris Digitally signed by Regiana M. Sistevaris
Date: 2020.05.19 15:42:54 -04'00'

Notary Public Regiana Maria Sistevaris

My Commission Expires January 7, 2023