COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company	)	
For Approval of A Certificate of Public Convenience	)	
And Necessity For Environmental Project	)	
Construction At The Mitchell Generating Station, An	)	Case No. 2021-00004
Amended Environmental Compliance Plan, And	)	
Revised Environmental Surcharge Tariff Sheets	)	

INITIAL BRIEF OF KENTUCKY POWER COMPANY

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TABLE OF CONTENTS

Page

I. INTRODUCTION

Kentucky Power Company ("Kentucky Power" or the "Company") seeks the Public Service Commission of Kentucky's ("Commission") approval in this case to complete the construction activities necessary to comply with the federal Coal Combustion Residuals ("CCR") Rule and the Steam Electric Effluent Limitation Guidelines ("ELG") Rule at the Mitchell Generating Station. This proceeding boils down to whether Kentucky Power should retain Mitchell Plant's capacity after 2028. That question can be answered based upon straightforward mathematical analysis and consideration of the clear consequences of the two alternatives.

No party opposes the Company's proposed approximately $18 million CCR Rule compliance investment, required for Mitchell to operate through 2028. Rather, intervenors challenge whether the Company also should make an approximately $49 million ELG Rule compliance investment, which would allow Mitchell to continue to operate until 2040. That relatively small ELG Rule compliance investment would preserve Kentucky Power's future resource options, including delaying hundreds of millions or billions of dollars in replacement investments, and would provide the Company time to evaluate developments in matters which are the subject of significant current uncertainty, such as the cost of replacement resources, PJM capacity market rules, and carbon legislation. Mitchell's capacity value, in the form of avoided high cost new resources, would be there for customers through 2040 regardless of how much energy Mitchell generates between now and then.

The enormous value that the comparatively small ELG investment brings to the Company and its customers through preservation of future options supports Commission approval of the Company's proposal to complete both CCR and ELG compliance investments and continue to operate Mitchell Plant until 2040. As detailed below, the Commission should approve the

Company's application, and authorize Kentucky Power to complete both CCR and ELG investments, as proposed.

II. BACKGROUND AND CASE OVERVIEW

A. The Mitchell Plant.

The Mitchell Plant is located approximately 12 miles south of Moundsville, West Virginia on the Ohio River.[1] Kentucky Power and Wheeling Power Company ("Wheeling Power") each own an undivided 50% interest in the Mitchell Plant.[2] The plant comprises two super-critical pulverized coal-fired base-load generating units.[3] Mitchell Unit 1 has a capacity of 770 MW and Mitchell Unit 2 has a capacity of 790 MW for a total capacity of 1,560 MW.[4] Both units were placed in service in 1971.[5] Each unit is equipped with an electrostatic precipitator for control of particulate matter, a flue gas desulfurization ("FGD") system for sulfur dioxide control, and selective catalytic reduction technology and low-nitrogen oxide ("NOx") burners for control of NOx emissions.[6] Both units also utilize a dry fly ash handling system.[7] Both units currently transport bottom ash and miscellaneous wastewater streams to a shared pond system where the bottom ash is later dredged and trucked to a permitted landfill.[8] The bottom ash transport water ("BATW") and miscellaneous wastewater streams are then discharged to the Ohio River through a National Pollution Discharge Elimination System permitted outfall.[9]

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[1] Sherrick Direct Test. at 3.
[2] *Id.*; Scott Direct Test. at 5.
[3] Sherrick Direct Test. at 3.
[4] *Id.*
[5] *Id.*
[6] *Id.*
[7] *Id.*
[8] *Id.*
[9] *Id.*

B. The CCR and ELG Rules.

The federal regulations that drive the need for the projects presented in the Company's Application and testimony are the CCR Rule and the ELG Rule.[10] The CCR Rule regulates the handling and storage of CCR material in an environmentally responsible manner.[11] The ELG Rule regulates wastewater discharges for the protection of surface water.[12]

On April 17, 2015, the United States Environmental Protection Agency ("EPA") published the CCR Rule to regulate the disposal and beneficial use of CCR, which includes fly ash (ash that is collected in electrostatic precipitators), bottom ash (ash that is collected from the bottom of a coal-fired boiler), and gypsum (a by-product of the flue gas desulfurization ("FGD") process) that are generated at coal-fired electric generating units through normal unit operation.[13] The rule applies to new and existing CCR landfills and CCR surface impoundments (ponds) at operating coal-fired electric generating facilities.[14] The rule defines construction and operation obligations for CCR handling and storage, including location restrictions (such as seismic stability requirements and a 5-foot minimum separation between the bottom of the pond and the uppermost aquifer); design criteria for storage areas (such as specifications for liners and caps to isolate stored CCR from the environment); structural integrity requirements for impoundments; and groundwater monitoring and protection requirements that include frequent sampling and analysis of groundwater to determine if it is impacted by the CCR storage site.[15] If any of the above criteria are unmet or are outside of EPA-established acceptable ranges, remediation steps

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[10] Spitznogle Direct Test. at 3.
[11] *Id.*; Scott Direct Test. at 5.
[12] *Id.*
[13] Spitznogle Direct Test. at 3
[14] *Id.*
[15] *Id.* at 3-4.

must be undertaken that could include any or all of the following: closure of the site, removal of the CCR material from the site, and/or groundwater treatment sufficient to attain applicable standards.[16]

On November 3, 2015, EPA published the ELG Rule revising effluent limitation guidelines for steam-electric generating facilities.[17] The rule established discharge limits on FGD wastewater, transport water used for fly ash and bottom ash handling, and other wastewaters.[18] EPA has revised the requirements of the ELG Rule, including applicable compliance dates, since the initial 2015 regulation.[19] The most recent revisions were finalized in October 2020.[20] The revised rule eliminates the discharge of most ash transport waters and requires enhanced treatment of FGD wastewaters.[21] These requirements are implemented through modifications to the existing state wastewater discharge ("NPDES") permit at Mitchell.[22]

The CCR Rule requires that, absent an extension, unlined CCR storage ponds (such as the bottom ash pond at the Mitchell Plant) must cease operations and initiate closure by April 11, 2021, which would require the Mitchell Plant to have ceased operations by that date.[23] The CCR Rule also has a retirement provision that allows time to complete the closure of existing ash ponds for facilities that plan to cease combusting coal or retire by a date certain.[24] In the case of

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[16] *Id.* at 4.

[17] *Id.*

[18] *Id.*

[19] *Id.*

[20] *Id.*

[21] *Id.*

[22] *Id.*

[23] *Id.* at 8. The Company timely requested an extension from EPA on November 30, 2020; that extension requests remains pending. Pursuant to the CCR Rule, the April 11, 2021 deadline is tolled pending EPA action on the extension request.

[24] Spitznogle Direct Test. at 8.

the Mitchell Plant, this retirement provision means that the bottom ash pond would be required to complete closure by October 17, 2023 and the Plant to cease operation even earlier that year.[25]

The ELG Rule also has a retirement option that would allow the Plant to continue discharging bottom ash transport water and FGD wastewater subject to specific limitations in exchange for a commitment to cease combusting coal or retire the plants by December 31, 2028.[26] Under the ELG retirement option, the Mitchell Plant would not be required to make additional capital investments in dry ash handling or wastewater treatment equipment to comply with the ELG Rule. This option can generally be referred to as a "CCR Only" option.[27] To take advantage of the ELG retirement option, facilities must notify the state permitting agency by October 13, 2021, that the ELG compliance strategy is to cease combusting coal or retire the generating unit.[28] The Company would then have 5 years to close, by removal, the new pond systems that were installed for CCR compliance.[29]

C. CCR and ELG Compliance Options and Alternatives Evaluated.

There are multiple options for compliance with the CCR and ELG Rules, each of which results in different requirements for plant operations and, potentially, plant retirement.[30] Company Witness Spitznogle analyzed the rules and discussed all of the potential compliance options with experts at Kentucky Power and AEPSC.[31] The Company ultimately selected to present to the Commission two compliance options, which are referred to throughout the Company's Application and supporting testimony as CCR and ELG ("Case 1"), or CCR only

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[25] *Id.*
[26] *Id.*
[27] *Id.*
[28] *Id.*
[29] *Id.* at 8-9.
[30] *Id.* at 7.
[31] *Id.*

("Case 2").[32] Case 1 enables ongoing operation under the requirements of both CCR and ELG Rules and would permit the Mitchell Plant to continue to operate until 2040;[33] and Case 2 meets the ongoing operational requirements under the CCR Rule but requires retirement by the end of 2028 under the ELG Rule.[34]

The proposed CCR and ELG compliance projects were identified through collaboration among AEPSC's Environmental Services, Engineering Services, Fossil & Hydro Generation, and Projects departments on behalf of Kentucky Power and Wheeling Power.[35] The Environmental Services department analyzed the rules, then the project teams (comprised of members from the other departments) defined the operational changes at the Plant that would be required to comply with the CCR and ELG Rules under the various compliance scenarios laid out under the rules.[36] Considering the timing requirements of various compliance scenarios established under the regulations, the Projects department then worked with a third-party vendor to develop schedules and cost estimates for the various compliance projects at the Plant.[37] The compliance projects then were submitted to the management of Kentucky Power and Wheeling Power for review and decision.[38]

The Company analyzed the actions needed to comply with the CCR and ELG Rules. To comply with the CCR Rule and to continue operating Mitchell through 2028, Kentucky Power is required to close the bottom ash pond at the Plant, which is unlined.[39] More specifically, the

[32] Mattison Direct Test. at 4-5.
[33] *Id.* at 5; Spitznogle Direct Test. at 5.
[34] Spitznogle Direct Test. at 5.
[35] Sherrick Direct Test. at 4.
[36] *Id.*
[37] *Id.*
[38] *Id.*
[39] Spitznogle Direct Test. at 5-6.

Company would be required to (i) remove ash from the existing ponds; (ii) over-excavate the ponds to ensure complete removal; (iii) install a new liner system in the footprint of the existing bottom ash pond to accept current CCR and non-CCR wastewater streams; and (iv) install a chemical treatment system for non-CCR wastewater streams.[40]

To comply with the ELG Rule and to operate Mitchell post-2028, Kentucky Power is required to convert the bottom ash handling equipment on the steam generating units at Mitchell to dry bottom ash handling systems and install bioreactors for treatment of FGD wastewater streams at the Plant.[41] More specifically, the Company must (i) modify the bottom ash handling systems to no longer allow the discharge of BATW, including the installation of submerged grind conveyor systems; (ii) install a new ash bunker; and (iii) install a new FGD Biological Treatment System with Ultrafiltration.[42]

AEPSC, on behalf of the Company, evaluated other CCR project options including installing large concrete troughs and remote dewatering conveyors.[43] Other ELG compliance options involved evaluating different vendor options to convert the wet bottom ash handling systems to dry systems.[44] AEPSC also evaluated closed loop recycle systems for ELG compliance.[45] However, given the CCR and ELG Rules and operational requirements for the Mitchell Plant, the project teams ultimately selected the proposed CCR and ELG projects, as described above, for consideration by Kentucky Power and Wheeling Power as they are the most technically feasible, least life cycle technology cost options.[46]

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[40] Sherrick Direct Test. at 4-5.
[41] Spitznogle Direct Test. at 6.
[42] Sherrick Direct Test. at 5.
[43] *Id.*
[44] *Id.*
[45] *Id.*
[46] *Id.*

1. Economic Analysis of CCR and ELG Compliance Options.

Company Witness Becker analyzed the economics of the two compliance options (Case 1 and Case 2). Each of the two compliance options was evaluated under three different fundamental pricing forecasts (Base with Carbon, Base No Carbon, and Low No Carbon), for a total of six scenarios.[47] Company Witness Becker used pricing information contained in the North American Long-Term Energy Market Forecast, referred to herein as the U.S. Energy Information Administration ("EIA")-based Fundamentals Forecast, sponsored by Company Witness Trecazzi.[48] The EIA-based Fundamentals Forecast is a long-term, weather-normalized commodity market forecast principally based upon the assumptions contained in the EIA's Annual Energy Outlook 2020 ("EIA AEO 2020").[49]

The total estimated cost of compliance that would allow the Mitchell Plant to continue to operate under the CCR and ELG requirements (Case 1) is $133.5 million.[50] Kentucky Power's share of that cost would be approximately $67 million.[51] Kentucky Power plans to fund the cost of the CCR and ELG compliance work through operating cash flow and other internally generated funds.[52] The total estimated cost of the CCR Only project (Case 2) is $35.1 million.[53] Kentucky Power's share of that cost would be approximately $18 million.[54]

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[47] Becker Direct Test. at 3.

[48] Trecazzi Direct Test. at 2-3.

[49] *Id.* at 3. Further information on the EIA-based Fundamentals Forecast and the EIA AEO 2020 can be found in the Direct Testimony of Company Witness Trecazzi at 3-8.

[50] Sherrick Direct Test. at 10.

[51] Scott Direct Test. at 6.

[52] Mattison Direct Test. at 9.

[53] Sherrick Direct Test. at 11-12.

[54] Scott Direct Test. at 7.

Company Witness Becker evaluated the compliance options based on the net present value ("NPV") of their cost and revenue impacts.[55] The NPV effects of the compliance decision at issue here largely rest on the incremental cost of CCR and ELG compliance, plus the future cost profile of Mitchell versus the next best option to replace it if it retires in 2028 without making the compliance investments.[56] The next best option in this context represents the lowest cost replacement resource, or combination of resources, which could be used to replace Mitchell.[57] A 2028 retirement of either of the two units at Mitchell will create a need for replacement capacity to cover the Company's peak load obligations.[58] Thus, the analysis necessarily required an evaluation of other capacity options compared to continued operation of Mitchell.[59]

The result of Company Witness Becker's NPV economic analysis for each compliance alternative was similar, resulting in a less than 1% difference in the total NPV between the two cases.[60] Thus, on an NPV basis, performing only the CCR compliance work at the Mitchell Plant and retiring the plant in 2028 has comparable costs and benefits to making the additional ELG investment required to allow operation of the plant beyond 2028, taking into consideration the entire study period used by Witness Becker.[61] As reflected in Table 1 in Witness Becker's testimony,[62] and reproduced below, under the NPV pricing scenarios that did not include a carbon burden, the CCR and ELG (Case 1) alternative is slightly better for customers.

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[55] Becker Direct Test. at 3.
[56] *Id.*
[57] *Id.* at 3-4.
[58] *Id.*
[59] *Id.*
[60] *Id*.
[61] *Id.*
[62] *Id*. at 4.

Table 1 - Incremental Cost of 2028 Retirement						
Kentucky Power Company's Half of Mitchell				NPV of Customer Revenue Requirement Increase / (Savings) Versus Case 1 ($ Millions)		
Case Number	Case Description	Retirement Year	Compliance Capital Cost ($ million)	Base With Carbon	Base No Carbon	Low No Carbon
Case 1	Mitchell CCR and ELG	2040	67			
Case 2	Mitchell CCR Only	2028	18	(6)	27	20

The small differences between the three fundamental scenarios, which contain a wide range of PJM market energy prices, indicates that the answer will be the same regardless of what future energy prices turn out to be, or if carbon legislation is enacted:[63] That is as expected, because this proceeding is about the avoidance of new near-term capacity costs, not energy value. Proceeding with both CCR and ELG (Case 1) would allow Kentucky Power to delay investment in replacement capacity for Mitchell until 2040.[64] If the Commission approved only the CCR investment (Case 2), customers would incur approximately $500 million of replacement capacity costs in 2028 under that scenario.[65] Thereafter, customers would be required to bear large net costs under Case 2 annually through 2039.[66] Approval of Case 1 avoids those significant costs through 2040.

2. Mitchell Replacement Options.

Company Witness Becker used the PLEXOS® model to produce the optimal resource plan and replacement options for Mitchell under 2028 and 2040 retirement dates.[67] The

[63] *See* Trecazzi Direct Test. at 6, Figure 2, "PJM AEP On-Peak Energy Prices (Nominal $/MWh)".
[64] Mattison Direct Test. at 5.
[65] *Id.* at 5-6; Becker Direct Test. at 8.
[66] Becker Direct Test. at 8.
[67] *See generally* Becker Direct Test. at 10-11.

nameplate capacity of the major additions selected by the model as replacements for Mitchell if it were to retire in 2040 (Case 1) are summarized in the top half of Table 4 contained in Company Witness Becker's Direct Testimony reproduced below.[68] The amounts also include replacements for Big Sandy 1, which is assumed to retire and be replaced in 2030.[69]

TABLE 4 - KPCo Optimal Major Replacement Capacity Additions Through the Retirement Year - Nameplate Megawatts

	Gas Combustion Turbines	Cumulative Solar	Cumulative Wind	Capacity Only PPA	**Total**
Case 1 - Mitchell CCR&ELG 2040 Retirement (Resource Additions from 2021-2040) *					
Base with Carbon	480	450	400	300	**1,630**
Base No Carbon	480	300	-	400	**1,180**
Low No Carbon	480	300		400	**1,180**
Case 2 - Mitchell CCR Only 2028 Retirement (Resource additions from 2021-2028) *					
Base with Carbon	480		400	150	**1,030**
Base No Carbon	480			200	**680**
Low No Carbon	480			200	**680**

* Case 1 additions through 2040 include replacements for both Mitchell and Big Sandy 1. Big Sandy 1 is assumed to retire in 2030. Case 2 additions through 2028 only include replacements for Mitchell.

Thus, after considering the results of all analysis, and taking other factors into account, Kentucky Power proposed to make the investments required for CCR and ELG compliance at the Mitchell Plant.[70] Making both the CCR and ELG compliance investments and keeping Mitchell's capacity online through 2040 provides capacity value to customers even if Mitchell produces less energy in the future than it typically did in the past.[71]

[68] *Id.* at 16-17.

[69] *Id.* at 16.

[70] Mattison Direct Test. at 6.

[71] *Id.*

D. Kentucky Power's Existing Environmental Compliance Plan, the 2021 Environmental Compliance Plan, and Project 22.

The Commission approved the Company's current ECP (the "2019 Plan") on May 18, 2020 in Case No. 2019-00389.[72] The 2019 Plan contains a total of 21 projects that have been approved by the Commission through various amendments since the Company's original ECP was approved in 1997.[73]

In this case, the Company proposes to add both the CCR and ELG projects (Case 1) to its Environmental Compliance Plan as "Project 22."[74] Project 22 will be placed in service in stages.[75] The Company forecasts the following in-service dates related to construction of the stages of Project 22:

- Dry Ash Handling System – May 2023
- Wastewater Ponds – November 2023
- Water Biological Treatment System with Ultrafiltration – April 2024[76]

The CCR Only Case requires only the construction and associated work in connection with the wastewater ponds.[77] The Company estimates that the wastewater pond construction in connection with the CCR Only Case would be placed in service in November 2023.[78]

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[72] Order, *Electronic Application Of Kentucky Power Company For Approval Of An Amended Environmental Compliance Plan And A Revised Environmental Surcharge*, Case No. 2019-00389 at 4 (Ky. P.S.C. May 18, 2020).

[73] Order, *Application of Kentucky Power Company d/b/a American Electric Power to Assess a Surcharge Under KRS 278.183 to Recover Costs of Compliance with the Clean Air Act and Those Environmental Requirements Which Apply to Coal Combustion Waste and By-Products* (Ky. P.S.C. May 27, 1997).

[74] Scott Direct Test. at 3; Ex. LMS-1.

[75] Scott Direct Test. at 5.

[76] *Id.* at 5-6.

[77] *Id.* at 6.

[78] *Id.*

E. Proposed Cost Recovery, Revisions to Tariff E.S., Return on Equity, Retail Impact, and Accounting Authority.

1. Cost Recovery through the Environmental Surcharge and Revisions to Tariff E.S.

Kentucky Power is seeking approval of a revised ECP to include the costs of the ELG and CCR work (Case 1) at the Mitchell Plant.[79] Kentucky Power proposes to recover the capital costs of Project 22 through the Environmental Surcharge ("Tariff E.S.").[80] Also, consistent with KRS 278.183(1), the Company proposes to include construction work in progress ("CWIP") for project construction costs in Tariff E.S. rate base and concurrently recover a return on project construction costs through Tariff E.S. rates.[81]

The Company's ECP includes projects determined to be cost-effective and required for the Company to comply with the Federal Clean Air Act and federal, state, and local requirements applicable to coal combustion wastes and by-products from coal-fired generation facilities ("Environmental Requirements").[82] The costs associated with these approved projects are recovered through a combination of base rates and the Environmental Surcharge.[83] There are two exceptions: a) the costs associated with the Mitchell Plant flue-gas desulfurization ("FGD") project and b) the costs associated with the Rockport Plant Unit 2 selective catalytic reduction system ("SCR").[84] The FGD costs are excluded from the Company's base rates pursuant to the Commission-approved Stipulation and Settlement Agreement in Case No. 2012-00578, and instead are recovered in their entirety through Tariff E.S.[85] The SCR costs are excluded from the

[79] Mattison Direct Test. at 9.
[80] *See* Scott Direct Test. at 8, 13.
[81] Whitney Direct Test. at 4.
[82] Scott Direct Test. at 3-4.
[83] *Id*. at 4.
[84] *Id.*
[85] *Id.*

Company's base rates, and recovered entirely through Tariff E.S., because the unit was not in-service during the test year ending March 31, 2020 used to establish Kentucky Power's base revenue requirement in Case No. 2020-00174.[86]

The Company proposes three changes to Tariff E.S. in this proceeding.[87] First, the Company is updating references to its ECP on tariff Sheet No. 29-3 to refer to the 2021 Plan, which includes Project 22.[88] Second, the Company is updating the list of environmental costs for the total company provided on Sheet No. 29-5.[89] Third, the Company is updating the list of environmental equipment at the Mitchell Plant on Sheet No. 29-6.[90]

2. Return on Equity.

Kentucky Power requests that the Commission approve the 9.10 percent return on equity ("ROE") established by the Commission in Case No. 2020-00174 for non-Rockport environmental compliance costs recovered through Tariff E.S.[91] This ROE was determined based upon a full cost of equity analysis and thorough Commission review in the Company's most recent base rate case.[92] It is reasonable to continue to use this recently-established ROE, authorized approximately one month before the Company filed this case, for purposes of this proceeding as well.[93] The Company's proposal in this regard also is consistent with recent Commission precedent.[94]

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[86] *Id.*

[87] Scott Direct Test. at 12; Ex. LMS-2; Ex. LMS-3.

[88] Scott Direct Test. at 12.

[89] *Id.*

[90] *Id.*

[91] Mattison Direct Test. at 10.

[92] *Id.*

[93] *Id.*

[94] Order, *In the Matter of: Electronic Application Of Duke Energy Kentucky, Inc. For A Certificate Of Public Convenience And Necessity To Construct Phase Two Of Its West Landfill And Approval To Amend Its Environmental Compliance Plan For Recovery By Environmental Surcharge Mechanism,* Case No. 2018-00156, at

3. Revenue Requirement and Retail Impact.

Project 22 is expected to be placed in service in multiple stages, with the last phase being placed in service April 2024.[95] In addition, the Company is proposing to add CWIP to the Environmental Surcharge rate base until the assets are placed in service.[96] Accordingly, Table 1 found in the Direct Testimony of Company Witness Scott, and reproduced below, outlines the annualized revenue requirement based on the various stages of Project 22:[97]

Table 1

Period	Period From*	Period To*	Revenue Requirement	Mos. In Period	Annualized Revenue Requirement
Period 1	Aug-21	Apr-23	$ 2,536,935	21	$ 1,449,677
Period 2	May-23	Oct-23	$ 2,796,202	6	$ 5,592,404
Period 3	Nov-23	Mar-24	$ 2,849,899	5	$ 6,839,758
Period 4	Apr-24	Mar-25	$ 8,166,153	12	$ 8,166,153

* Expense Month

The periods provided in Table 1 align with the following Project 22 milestones:

• Period 1: Begin to include CWIP as a component of the environmental surcharge rate base.

• Period 2: Dry Ash Handling System is estimated to be placed into service (May 2023).

• Period 3: Wastewater Ponds are estimated to be placed into service (November 2023).

• Period 4: Water Biological Treatment System with Ultrafiltration is estimated to be placed into service (April 2024).[98]

10-11 (Dec. 10, 2018) (approving Duke Energy Kentucky, Inc.'s proposal to use the ROE that had been established in its then-most recent base rate case two months before its ECP application).

[95] Scott Direct Test. at 6.

[96] *Id.*

[97] *Id.* at 6-7.

[98] *Id.* at 7.

Should the Commission instead approve Case 2 (CCR Only), there would be only two periods related to project milestones.[99] Period 1 provides for the inclusion of CWIP in the environmental surcharge rate base until the assets are placed in service.[100] Period 2 starts with the wastewater ponds being placed in service.[101] Table 2 found in the Direct Testimony of Company Witness Scott outlines the annualized revenue requirement for these two periods.[102]

The revenue requirements above do not include the costs previously identified for ARO and other charges, as those have been proposed by the Company to be recovered through base rates.[103]

Based on the revenue requirement for Project 22, for a residential customer using 1,219 kWh per month, the monthly increase in the customer's total bill if the Commission approves Case 1 is expected to be $0.40 (or 0.28%) beginning in October 2021 (Period 1) and increasing to $2.26 (or 1.58%) beginning in July 2024 (Period 4).[104] Exhibit LMS-5 provides detailed calculations of the estimated monthly impact of the environmental surcharge for both residential and all other rate schedules.[105]

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[99] *Id.* at 8.
[100] *Id.*
[101] *Id.*
[102] *Id.*
[103] *Id.* at 8; Whitney Direct Test. at 8.
[104] Scott Direct Test. at 11.
[105] *Id.*

4. Accounting Treatment and Proposed Depreciation Rates.

The Company will record construction costs for Project 22 to FERC Account 107 before transferring the completed construction cost to FERC Account 101 when the projects are placed in service.[106] The Company will then record related depreciation expense to FERC Account 403 and corresponding accumulated depreciation to FERC Account 108.[107] For Tariff E.S. purposes, and consistent with ratemaking treatment in base rates, the Company proposes to reflect Project 22 (CCR and ELG (Case 1)) assets described in this case as a component of rate base (CWIP and electric plant in service less accumulated depreciation and less related deferred income taxes) in order to calculate a return on rate base and include such return along with the related depreciation expense as recoverable costs of service.[108] The Company's monthly Tariff E.S. over-/under-recovery balance calculation and related accounting results in collection of actual, allowed incurred costs through Tariff E.S. rates.[109]

The Company's depreciation rates for the Mitchell Plant were last updated as a result of the settlement approved by the Commission in Case No. 2017-00179, and are based on plant in-service balances at December 31, 2013 and an expected estimated retirement date of 2040.[110] For Case 1, the Company proposes a 5.86% annual depreciation rate for CCR and ELG investments at Mitchell based on a weighted average remaining life of 17.08 years.[111]

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[106] Whitney Direct Test. at 5.
[107] *Id.*
[108] *Id.*
[109] *Id.* at 5-6.
[110] *Id.* at 6.
[111] *Id.*

For Case 2, the Company proposes a 20% annual depreciation rate for the CCR only investments at Mitchell based on an in-service date of November 2023 and closure of the plant in December 2028 (remaining life of 5 years).[112]

Further, if the Commission approves Case 2, the Company requests that the Commission:

• Conclude that any incurred Kentucky jurisdictional Mitchell Plant ELG costs are prudently incurred on behalf of customers, and

• Include specific provisions in the final order in this proceeding authorizing the creation of a corresponding regulatory asset subject to carrying charges based on an authorized pre-tax weighted average cost of capital ("WACC") of 7.62% until the regulatory asset is fully recovered.[113]

The Company would then request amortization of deferred Mitchell Plant ELG costs in a future base rate filing.[114]

III. LEGAL STANDARDS

A. Certificate of Public Convenience and Necessity.

Kentucky Power must obtain a certificate of public convenience and necessity prior to beginning construction of "any plant, equipment, property, or facility for furnishing…" service to the public[115] except where the proposed work constitutes an extension in the ordinary course of business.[116] KRS 278.020(1) provides for the grant of a certificate of public convenience and necessity upon the Company's showing of the need for the proposed construction *and* the

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[112] *Id.*
[113] *Id.* at 7.
[114] *Id.*
[115] KRS 278.020(1).
[116] 807 KAR 5:001, Section 15(3).

absence of wasteful duplication.[117] Need may be demonstrated by, *inter alia*, the existence of "a substantial deficiency of service facilities beyond what could be supplied by normal improvements in the ordinary course of business…."[118] Wasteful duplication comprises two elements: (a) excess of capacity over need; or (b) excess investment in relation to productivity and efficiency to be gained from the proposed construction.[119] The absence of wasteful duplication also requires a demonstration that all reasonable alternatives were examined.[120]

B. Environmental Compliance Plan.

KRS 278.183 provides that a utility shall be entitled to the current recovery of its costs of complying with the Federal Clean Air Act, as amended, and those federal, state, or local environmental requirements that apply to coal combustion wastes and byproducts from facilities utilized for the production of energy from coal. Pursuant to KRS 278.183(2), a utility seeking to recover its environmental compliance costs through an environmental surcharge must first submit to the Commission a plan that addresses compliance with the applicable environmental requirements. The plan must also include the utility's testimony concerning a reasonable return on compliance-related capital expenditures and a tariff addition containing the terms and conditions of the proposed surcharge applied to individual rate classes. Within six months after submission of an ECP, the Commission must: (1) consider and approve the plan and rate surcharge if the plan and rate surcharge are found reasonable and cost-effective for compliance

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[117] *Kentucky Utilities Co. v. Public Serv. Comm'n*, 252 S.W.2d 885, 890 (Ky. 1952).

[118] *Id.*

[119] *Id.*

[120] *In the Matter of: Joint Application Of Louisville Gas and Electric Company And Kentucky Utilities Company For A Certificate of Public Convenience and Necessity For The Construction of Transmission Facilities In Jefferson, Bullitt, Meade, and Hardin Counties, Kentucky* Case No. 2005-00142 (Ky. P.S.C. September 8, 2005).

with the applicable environmental requirements; (2) establish a reasonable return on compliance-related capital expenditures; and (3) approve the application of the surcharge.[121]

IV. THE COMMISSION SHOULD APPROVE THE COMPANY'S REQUEST FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO MAKE THE INVESTMENTS REQUIRED FOR BOTH CCR AND ELG COMPLIANCE AT THE MITCHELL PLANT, IT SHOULD APPROVE THE COMPANY'S 2021 ENVIRONMENTAL COMPLIANCE PLAN AND REVISED TARIFF E.S. AS PROPOSED, AND IT SHOULD GRANT THE COMPANY'S REQUESTED ACCOUNTING AUTHORITY.

A. Project 22 is Necessary to Comply with US EPA's CCR and ELG Rules and Will Not Result in Wasteful Duplication.

As detailed in Section II.B above, completion of CCR and ELG compliance work at the Mitchell Plant is required to comply with federal environmental regulations in order for the plant to continue to operate after April 11, 2021.[122] Simply put, if Kentucky Power does not undertake the work necessary to comply with either the CCR Rule or ELG Rule, the rules require the Mitchell Plant to shut down immediately. If Kentucky Power undertakes the work necessary to comply with the CCR Rule but not the ELG Rule, the ELG Rule requires the Mitchell Plant to shut down at the end of 2028.

For the same reason, the CCR and ELG Rules' requirements as they apply to the operation of the Mitchell Plant are among the Environmental Requirements described in KRS 278.183 and are properly recoverable through the Environmental Surcharge.

Nor will Project 22 result in wasteful duplication. Importantly, no party claims that it would. Wasteful duplication is defined as "an excess of capacity over need" and "an excessive investment in relation to productivity or efficiency, and an unnecessary multiplicity of physical

[121] KRS 278.183(2).
[122] Mattison Direct Test. at 9.

properties."[123] "As implied by that definition, there must be an actual need for a project for the Commission to find that it will not result in wasteful duplication."[124] It is undisputed that Kentucky Power must complete CCR and ELG compliance work at Mitchell Plant in order for the plant to continue to operate after April 11, 2021.

Retiring the Mitchell Plant on April 11, 2021 would have left Kentucky Power, on very short notice, without 780 MW of capacity that has already has been committed to meet PJM's capacity requirements through May 2022.[125] Moreover, with the December 7, 2022 expiration of the Rockport UPA, Kentucky Power would be left with less than 300 MW of capacity to meet its capacity requirements of approximately 1,000 MW.[126] Based on these numbers, making the ELG and/or CCR investments in order to keep the Mitchell Plant operating and providing capacity value objectively does not result in wasteful duplication.

B. The Commission Should Authorize Case 1 (CCR and ELG); Intervenors' Arguments in Support of Case 2 (CCR Only) Are Flawed and Unavailing.

As detailed above, the Company's economic analysis demonstrates that Case 1 (CCR and ELG) would result in greater NPV savings than Case 2 (CCR only) and therefore provides greater benefits to customers and the Company. Accordingly, Kentucky Power is seeking approval of Case 1, reflected in proposed Project 22 for its ECP, in this proceeding. AG/KIUC and Sierra Club have recommended that the Commission approve Case 2, which would require Mitchell Plant to retire in 2028. Intervenors' positions, however, are based on flawed analyses and incorrect information, as detailed below. The record evidence supports ELG and CCR.

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[123] Order, *In the Matter of: Electronic Application Of Duke Energy Kentucky, Inc. For An Order Declaring The Construction Of Solar Facilities Is An Ordinary Extension Of Existing Systems In The Usual Course Of Business*, Case No. 2020-00385, at 6 (Mar. 1, 2021).

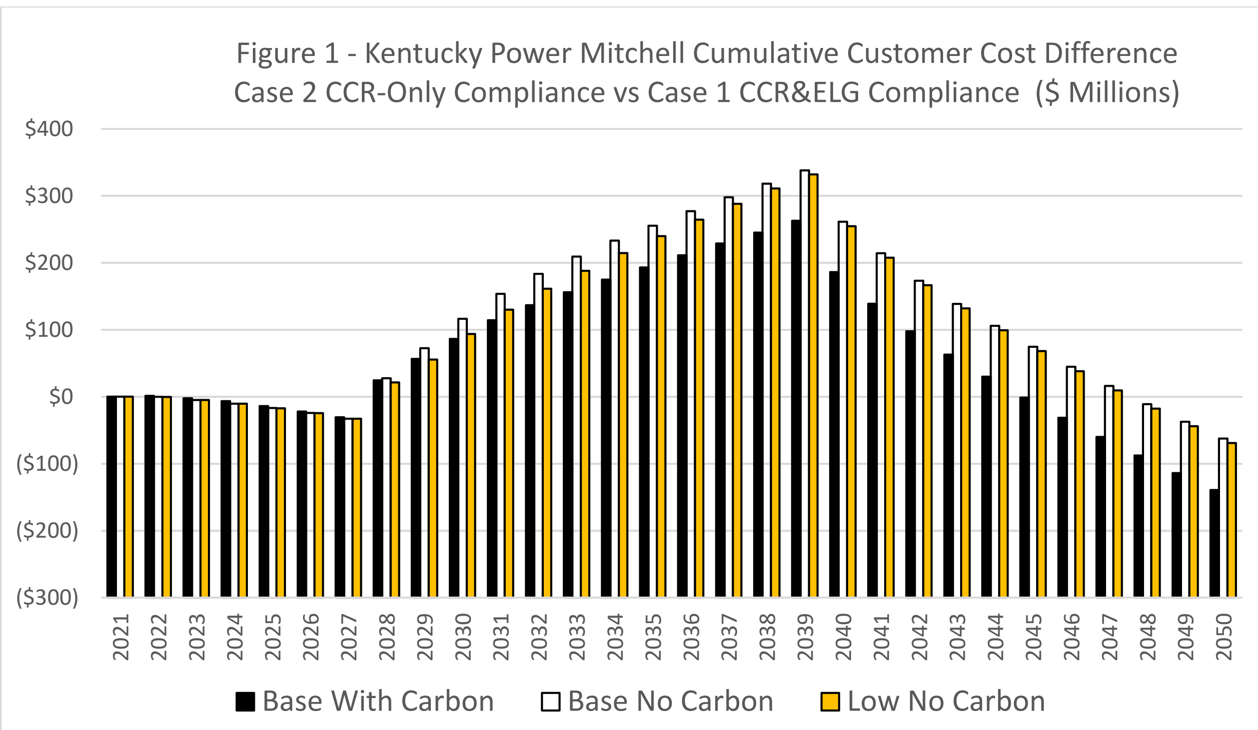
[124] Mattison Direct Test. at 6-7.

[125] *Id*. at 8.

[126] *Id*.

1. The Company's Economic Analysis Supports Case 1.

AG/KIUC Witness Kollen's contentions that the quantitative results of the Company's economic analysis are "very close"[127] and that Case 1 exposes Kentucky Power to greater economic risk than retirement of Mitchell Plant in 2028[128] are incorrect. As an initial matter, it is telling that Mr. Kollen offers no analysis or quantification of the supposed increased economic risk that he claims is associated with Case 1. His unsupported opinion should be disregarded on that basis alone. Moreover, Mr. Kollen's opinions are refuted by the Company's economic analysis. As Company Witness Becker demonstrated, running Mitchell until 2040 under Case 1 is expected to be $260 million to $340 million <u>less expensive,</u> on a nominal basis, under all three of the Company's fundamentals forecasts over the next approximately 20 years than retiring the plant in 2028 under Case 2:[129]



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[127] Kollen Test. 13.

[128] *Id*. at 7.

[129] Becker Rebuttal Test. at R12.

Contrary to Mr. Kollen's assertion, a $260 to $340 million difference is not "very close."

Moreover, the significant savings under Case 1 "clearly indicate that there is limited economic risk in Mitchell's continued operation" to 2040.[130] Investing $49 million in ELG will provide significant customer savings by delaying hundreds of millions of dollars of replacement capacity costs.[131] Those net customer benefits will begin to be realized by 2028.[132] Conversely, under Case 1, "customers will incur approximately $500 million of replacement capacity costs in 2028 that [c]ould be delayed by over a decade by making the $49 million investment to comply with the ELG rule."[133]

2. AG/KIUC's Criticisms of the Company's Economic Analysis Are Without Merit.

The Commission also should disregard AG/KIUC's inaccurate criticisms of the Company's economic analysis, which overstate the impact of what AG/KIUC incorrectly claim to be modeling errors. As demonstrated below, the impact of AG/KIUC Witness Kollen's proposed revisions to the Company's PLEXOS analysis, when corrected to address flaws in Mr. Kollen's proposals, is immaterial.

Mr. Kollen first compares apples to oranges by advocating that supposedly lower-cost solar PPAs should be considered against the levelized cost of owned solar resources in the Company's economic analysis.[134] The Commission should disregard that erroneous suggestion for several reasons. First, as Company Witness Becker explained, it is inappropriate to compare

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[130] *Id.* at R13.
[131] *Id.*
[132] *Id.*
[133] *Id.*
[134] Kollen Test. at 14-16.

the 20-year PPAs described by Mr. Kollen to the 30-year operating life owned resources included in the Company's analysis.[135] In order to make a reasonable comparison of those two alternatives, the resources would need to be of a similar operating life.[136] Thus, the 20-year PPAs Mr. Kollen identified would need to be replaced at some cost at the end of their 20 year life by a PPA(s) with a 10-year life so that the Company and the PPA alternatives would have similar operating lives.[137] During the 10-year period when additional resources have to be added after the expiration of the 20-year PPAs, the 30-year owned resource would have depreciated by two-thirds of its original cost.[138] That lower rate base would make the 30-year owned resource more affordable than a new asset for those last 10 years of the owned asset's life.[139] Mr. Kollen's proposal also fails to recognize that the solar PPAs he references are due to come on-line in 2023, several years before Kentucky Power would need the capacity to replace Mitchell if it were to retire in 2028.[140]

Moreover, were it possible to acquire PPAs at the costs Mr. Kollen describes when Kentucky Power needed the capacity in 2028, the retirement savings only increase from $6 million to $14 million, out of a total cost of $4.3 billion over the 30 year analysis period – <u>or less than 0.2%</u>.[141] Finally, assuming the understated solar PPA pricing Mr. Kollen suggests in the model could result in the model finding it economic to add the same capacity levels in both Case

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[135] Becker Rebuttal Test. at R13.
[136] *Id.*
[137] *Id.*
[138] *Id.*
[139] *Id.*
[140] *Id.* at R14.
[141] *Id.*

1 and Case 2.[142] If this occurred, then there would be <u>no cost savings</u> attributable to the addition of those resources.

Mr. Kollen also argues that the Company erred by not including a 10% solar investment tax credit ("ITC") for projects that go in service after 2024.[143] As Company Witness Becker responded, however, the solar resources that are critical to the decision in this case are those that are added prior to the potential replacement of Mitchell capacity in 2028 under Case 2.[144] The solar levelized cost of energy for those resources is only overstated by approximately 4%, and only for the three years prior to a 2028 Mitchell retirement under that case.[145]

Finally, Mr. Kollen criticizes the Company's capital costs of new combustion turbine resources, averring that the Company failed to escalate those costs using a reasonable annual escalation rate.[146] Upon reviewing Mr. Kollen's testimony, the Company determined that it had provided an incorrect discovery response, upon which Mr. Kollen's opinion was based, and promptly corrected the discovery response.[147] As the corrected data response reflects, the combustion turbine escalation rates used in the Company's model averaged 2.54% over the analysis period, which is virtually the same as Mr. Kollen's suggested 2.5% escalation rate.[148] Thus, the Company's modeling already is consistent with this recommendation by Mr. Kollen.

In summary, after corrections, Mr. Kollen's proposed revisions to the Company's PLEXOS analysis are minimal.[149] It is therefore unnecessary for the Company to rerun its

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[142] *Id.*
[143] Kollen Test. at 27.
[144] Becker Rebuttal Test. at R14-R15.
[145] *Id.*
[146] Kollen Test. at 17-19.
[147] Becker Rebuttal Test. at R15.
[148] *Id.*
[149] *Id.* at R16.

PLEXOS analysis because Mr. Kollen's proposals do not materially impact the Company's modeling and do not change the conclusion supporting Commission approval of Case 1.[150]

3. Sierra Club's Incomplete Analysis Recommending the Retirement of the Mitchell Units in 2028 is Premised upon Unrealistic Assumptions and Makes Improper Use of the Data.

The Commission and the Company must address the requirements of the CCR and ELG Rules in the real world. They do not have the luxury of assuming boundless resources, unlimited capital, or the existence of cost-free transmission upgrades to permit the import of wind energy into the Commonwealth.[151] Nor do the Company and the Commission operate in a world where costs such as depreciation, income and property taxes, and general and administrative expenses can be ignored, or where markets are free to ignore supply and demand with impunity. Sierra Club's analysis is rooted in each of these non-real world assumptions and more. Sierra Club's analysis also incorporates the July 2020 National Renewable Energy Laboratory ("NREL") "R&D Case" in a fashion that is inconsistent with its intended purpose.

The result of each of these failures by Sierra Club to operate in the real world is to render the Sierra Club's "Synapse 2028 Retirement" proposal unrealistic, risky, and not a credible basis for deciding how Kentucky Power, in the face of the requirements of the CCR and ELG Rules, must plan to provide adequate, efficient, and reasonable service in return for fair, just, and reasonable rates. Most importantly, Sierra Club ignores the fact that the relatively modest $49 million additional investment by Kentucky Power in the ELG projects[152] will allow the

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[150] *Id.*

[151] Becker Rebuttal Test. at R2, R3, and R16.

[152] Sherrick Direct Test. at 10-12.

Company, and its customers to delay the hundreds of millions, if not billions, of dollars of investment required under the "Synapse 2028 Retirement" proposal.[153]

a. Sierra Club's Synapse 2028 Retirement Case.

Sierra Club recommends that the Commission authorize only "the proposed CCR compliance capital projects and deny the CPCN for the ELG projects."[154] The recommendation is premised upon an analysis performed by Synapse Energy Economics, Incorporated for Sierra Club by Ms. Wilson. The modeling compares the net present value revenue requirement ("NPVRR") of making the investments needed to comply with the CCR Rule and the ELG Rule (labeled "Business as Usual" or "BAU" by Sierra Club) with completing only the work required to comply with the CCR Rule and retiring the Mitchell Plant at the end of 2028 (labeled "Synapse 2028 Retirement" by Sierra Club). Sierra Club contends that the NPVRR of the Synapse 2028 Retirement option is $194 million less under a Base No Carbon case[155] and $341 million less under a Base with Carbon case[156] than the NPVRR if the Company also made the ELG investments and continued to operate Mitchell through 2040.[157]

Sierra Club's Synapse 2028 Retirement option would require an unprecedented investment by Kentucky Power in new generation resources. Between now and when Mitchell Plant retires, the Synapse 2028 Retirement case would require Kentucky Power to acquire 1,500 MW of new nameplate capacity under the Base No Carbon case (1,500 MW of solar and no

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[153] Sierra Club Response to Kentucky Power Data Request 1-10, *In the Matter of: Electronic Application Of Kentucky Power Company For Approval of A Certificate of Public Convenience And Necessity For Environmental Project Construction At The Mitchell Generating Station, An Amended Environmental Compliance Plan, And Revised Environmental Surcharge Tariff Sheets*, Case No. 2021-00004 at 7 (Ky. P.S.C. Filed June 8, 2021) ("Sierra Club DR Response 1-__").

[154] Wilson Test. at 7.

[155] *Id*. at 26 (Table 9 "Net present value of revenue requirements, Synapse modelling scenarios").

[156] *Id*.

[157] *Id*. at 6. Sierra Club did not analyze the Company's NPVRR using a Low Band case. Becker Rebuttal Test. at R3.

wind) costing $2 billion and 2,200 MW of new nameplate capacity under the Base with Carbon case (1,800 MW solar and 400 MW of wind) costing $2.8 billion. All told, between now and 2050, the Sierra Club's analysis would have the Company build 2,325 MW of new nameplate capacity under the Base No Carbon case (2,200 MW of solar and 125 MW of gas) and 3,585 MW of new nameplate capacity under the Base with Carbon case (2,160 MW solar; 1,300 MW wind; and 125 MW of gas).[158] Paradoxically, Sierra Club's analysis indicates that Kentucky Power would be required to acquire even more generating and other capacity resources between now and 2050 if Mitchell were permitted to run through 2040: 2,401 MW under the Base No Carbon case (2,240 MW solar; 125 MW gas; and 36 MW storage) and 4,297 MW under the Base with Carbon case (2,160 MW solar; 2,000 MW wind; 12 MW storage; and 125 MW gas). Stated otherwise, Sierra Club's analysis indicates that even with Mitchell available to provide capacity and energy, Kentucky Power requires 3.2 percent additional capacity under the Base No Carbon case and almost 20 percent additional capacity under the Base with Carbon case than if Mitchell retired in 2028.

The Sierra Club analysis in part used inputs different from those employed by Kentucky Power. These differences include significantly lower costs for battery storage, wind, and solar resources than employed by Kentucky Power in pricing replacement resources.[159] Part of the difference resulted from an error in the calculation of the nominal rate of return on investment.[160] These lower prices also reflect Sierra Club's failure to include in its modeling real world considerations such depreciation expense, income taxes, property taxes, and general and

[158] Wilson Test. at 6 (Table 1 "Summary of Synapse modeling results (2050)").

[159] *Id*. at 24 (Table 8 "Comparison of prices for new resources in KPC and Synapse modeling"). Kentucky Power's prices for wind were lower in 2023 and 2024 than those used by Sierra Club.

[160] Becker Rebuttal Test. at R9.

administrative expenses.[161] Sierra Club also assumed that fixed O&M (such as land leases, insurance, and wages) would decline by 47 percent between 2018 and 2030.[162]

Conversely, Sierra Club adopted Kentucky Power's energy prices under the Company's Base No Carbon and Base with Carbon cases.[163] If Kentucky Power had access to these low cost renewable resources, then the expectation would be that other utilities in PJM would have access to them as well, and also add significant amounts of renewable resources. The higher energy prices of the Base No Carbon and Base with Carbon cases are inconsistent with the significant renewable penetration, along with their accompanying zero or near zero variable costs reducing the energy prices.[164] The lower energy prices likely to result from the increased penetration of renewable resources were available to Sierra Club in the Company's Low No Carbon fundamental forecast.[165] Sierra Club elected, without explanation in its direct testimony, not to present the results of its analysis, if any, of using Kentucky Power's Low No Carbon forecast.[166]

b. Sierra Club's Synapse 2028 Retirement Case is Impracticable, Risky, and Will Impose Unreasonable Costs on Kentucky Power and its Customers.

Kentucky Power currently owns or contracts for 1,467 MW of installed capacity.[167] Sierra Club, in connection with its Synapse Retirement 2028 proposal, recommends that by 2050 Kentucky Power acquire 3,585 MW of nameplate solar, storage, and wind capacity.[168] That is an

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[161] *Id.* at R8.

[162] *Id.*

[163] *Id.* at R11.

[164] *Id.*

[165] *Id.*

[166] *Id.*

[167] Big Sandy Unit 1 (295 MW); Mitchell Units 1 and 2 (780 MW); and Rockport Unit Power Agreement (392 MW). The Rockport Unit Power Agreement expires December 7, 2022. Kentucky Power previously announced it will not renew the Rockport agreement.

[168] Wilson Test. at 6 (Table 1).

amount nearly two and one-half times the Company's current installed capacity.[169] Stated otherwise, this radical and unprecedented transformation of the Company's capacity would result in a 50 percent to 100 percent reserve margin between 2026 and 2028 (when Sierra Club's analysis would require Mitchell to retire),[170] and obligate Kentucky Power to acquire capacity equal to nearly four times the Company's projected 2050 peak load obligation of 900 MW.[171]

Critically, the Synapse 2028 Retirement proposal front loads this transformation by obligating Kentucky Power to acquire *annually* on average 450 MW of solar capacity, an amount nearly equal to one-third its existing installed capacity, for four consecutive years beginning in 2026 under the Base With Carbon case.[172] Sierra Club's Synapse 2028 Retirement proposal assumes the Company could obtain the necessary regulatory approvals[173] to add 2,200 MW of additional capacity[174] in the four year period between 2026 and 2029. Sierra Club offers no evidence that this additional capacity is, or will become, available when needed by Kentucky Power, or equally important, that Kentucky Power can secure this renewable capacity in competition with "other utilities, large companies, and federal, state, and local governments with clean energy mandates and aspirations"[175] Likewise, Sierra Club ignores the significant challenges facing the Company, or third party developers, of obtaining sufficient land (15,000 acres, or nearly 23.4 square miles[176] in the case of solar generation) to build the generation required just for Kentucky Power.[177]

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[169] Becker Rebuttal Test. at R4.
[170] *Id*. at R5.
[171] *Id*. R4.
[172] *Id*. at R4.
[173] *Cf.* KRS 278.020(1); KRS 278.300.
[174] Sierra Club DR Response 1-11.
[175] Becker Rebuttal Test. at R4.
[176] 15,000 acres / 640 acres/square mile = 23.4 square miles.
[177] *Id*. at R5.

Unlike the relatively modest additional investment of approximately $49 million required to comply with the ELG Rule,[178] and the more reasonable timeline for deploying new resources the additional ELG investment permits Kentucky Power to undertake, the Synapse Retirement 2028 proposal requires Kentucky Power to make, and Kentucky Power's customers to pay for, $2.8 billions of dollars of investments in new solar and wind facilities by 2029.[179] In addition, the 2028 retirement of the Mitchell Plant would further burden Kentucky Power's customers as early as 2029 with increased rates to recover the remaining net book value ("NBV") of Mitchell. Finally, the "savings" Sierra Club claims under its Synapse Retirement 2028 proposal in part flow from projected off-system energy sales by the Company from capacity far in excess of what it needs.[180] This future envisioned for the Company by the Sierra Club turns it into more of merchant power producer than a regulated utility. The affordability of Kentucky Power customers' rates, the financial health of Kentucky Power, and perhaps the economic future of the Company's service territory should not be gambled on such a risky throw of the dice.

c. Sierra Club's Synapse 2028 Retirement Proposal Rests on Incomplete and Misapplied Data and Unrealistic Assumptions.

The Sierra Club modeling that produced the NPVRR savings Sierra Club claims for its Synapse 2028 Retirement Proposal rests in part on Ms. Wilson's election to substitute NREL R&D Case costs and capacity factors for replacement solar, wind, and battery storage resources.[181] As an initial matter, the NREL R&D data for the cost of the replacement additions, although useful for its intended purpose, are not, as Ms. Wilson contends, "industry standard

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[178] Sherrick Direct at 10-12.
[179] Becker Rebuttal Test. at R6.
[180] *Id*. at R4.
[181] Wilson Test. at 17 (Table 6 "Sources of input assumptions in Synapse modeling").

pricing" for the purposes used by Sierra Club.[182] The NREL levelized cost of energy values used by Sierra Club in its modeling are based on aggressive developer capital structures and low rates of return and do not accurately reflect the full cost of either Company ownership or the price of a 30 year PPA.[183]

The Sierra Club modeling, and particularly the manner in which it employs the NREL data, significantly understates the costs of the solar, wind, and battery storage replacement resources[184] and thereby overstates the "savings" to be produced by the Synapse 2028 Retirement proposal. More particularly,

◊ The NREL data used by Sierra Club for the fixed cost of the replacement resources exclude depreciation expense, income tax, property tax, along with general and administrative expenses. Each of these real world expenses will be incurred and borne by Kentucky Power's customers, whether the assets are owned or obtained by PPA.[185] The failure of Sierra Club to account for these omissions unreasonably skews its modeling toward the Synapse 2028 Retirement proposal.

◊ Sierra Club's miscalculation of the conversion of NREL's real dollar capital recovery factor to a nominal capital recovery factor in its modeling – understated the cost of the resources added.[186] Again, this error understates a real world cost thereby making the addition of solar, wind, and battery storage resources appear more affordable and inflating the claimed NPVRR savings.

◊ Sierra Club's modeling assumes, based on declining capital costs in the NREL data, that fixed O&M, including costs such as land lease payments, insurance, and maintenance employee-related costs likewise will decline in real dollar terms over the 30-year modeling period. This is despite the fact that such costs are not linked to technology-related capital costs, and thus would not be expected to decline.[187] Indeed, Sierra Club forecasts fixed O&M costs will decline nearly 50 percent between 2018 and 2030.[188]

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[182] Becker Rebuttal Test. at R4.

[183] *Id*. at R7-R8.

[184] For example, the modeling assumes that "stand-alone solar will be available between 2026 and 2040 at an average cost of approximately $26.00/MWh." *Id*. at R4.

[185] *Id*. at R8.

[186] *Id*. at R9.

[187] *Id*. at R9-R10.

[188] *Id*. at R10.

◊ Sierra Club's modeling relies upon NREL solar capacity factors (based on estimated capacity factors for Missouri solar facilities) that overstate the solar capacity factors for existing solar projects in the PJM footprint.[189] The effect is to *understate* the cost of the modeled solar resources and *overstate* the revenues to be produced by these facilities.[190] These errors act in tandem to increase "the solar energy profits embedded in her resource plan" and thereby unrealistically increase the cost advantage for the Synapse 2028 Retirement proposal.[191]

◊ Sierra Club's use of the understated NREL fixed costs for solar and wind replacement resources, without adjusting market energy prices downward to reflect their zero or near-zero variable costs that would displace fossil generation that carries fuel and other variable costs, again overstates the energy market profits used to support the Synapse 2028 Retirement proposal.[192] Sierra Club could have more accurately modeled this effect by using Kentucky Power's Low Band fundamentals forecast.[193] It elected without explanation in Ms. Wilson's direct testimony to not do so.[194]

These fundamental errors skew Sierra Club's modeling results and render them an unrealistic and non-credible basis for the wholesale transformation of Kentucky Power's generation resource fleet advocated by Sierra Club.

4. The Commission Should Disregard AG/KIUC's Suggestion to Consider Hypothetical Future Securitization Financing in Evaluating the Company's Proposals in This Case.

The Commission also should reject AG/KIUC Witness Kollen's unfounded and speculative suggestion that the Commission consider savings that purportedly "could be achieved through securitization financing" if Mitchell Plant is retired in 2028.[195] As Mr. Kollen himself recognizes, securitization financing <u>is not available or authorized by Kentucky law</u>.[196] Rather, as Company Witness Mattison explained:

> The reality . . . is that securitization is not possible in Kentucky at this time, and it is unknown whether it ever would be authorized in connection with the Company's

[189] *Id.*

[190] *Id.* at R10-R11.

[191] *Id.*

[192] *Id.* at R11.

[193] *Id.* at R3.

[194] *Id.*

[195] Kollen Test. at 25-27.

[196] *Id.*; Mattison Rebuttal Test. at R2.

> costs of satisfying its [CCR and ELG] compliance obligations. The process of working with legislators to make securitization a reality could take many years, and there are no guarantees it would ever become law in Kentucky. For example, securitization was discussed in the Commission's August 22, 2005 assessment of the Commonwealth's electric infrastructure, yet more than 15 years later the required legislation has yet to be enacted.[197]

The Company's economic analysis is not flawed for not considering a financing option that does not exist, has no guarantee of ever existing, and has not come into existence in nearly two decades since it was discussed in the context of Kentucky's electric infrastructure.

Moreover, it is impossible for Mr. Kollen to credibly attempt to quantify savings under Case 2 associated with fictional securitization legislation that is uncertain to ever exist, and whose provisions and requirements are unknowable. For the same reasons, it is not credible for Mr. Kollen to claim that securitization financing, if available, would only create savings in a 2028 retirement scenario.[198] As Company Witness Mattison explained, were securitization available – which it is not – its benefits would need to be considered under both Case 1 and Case 2, as it is "virtually certain that the Mitchell Plant will have a positive net book value in either 2028 or 2040."[199] It is simply impossible to know whether nonexistent securitization legislation would permit the securitization of the Mitchell Plant NBV remaining under Case 1, to value those benefits, or to compare them to expected benefits under Case 2

In sum, it would be wholly inappropriate for the Commission to base its decision in this proceeding on the speculative and uncertain "possibility" of securitization financing being available, as Mr. Kollen advocates, and the Company's economic analysis is not deficient for not considering that unquantifiable and uncertain possibility.[200]

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197 Mattison Rebuttal Test. at R2-R3.

198 Kollen Test. at 25.

199 Mattison Rebuttal Test. at R2.

200 *Id.* at R3; Kollen Test. at 6.

5. Contrary to AG/KIUC's Speculation, Case 2 Does Not Provide Greater Flexibility than Case 1.

AG/KIUC Witness Kollen's assertion that Case 2 is more favorable than Case 1 because Case 2 would provide greater flexibility to a potential future owner of Kentucky Power[201] is both speculative and incorrect. As Kentucky Power President and Chief Operating Officer Witness Mattison explained, AEP is currently conducting a strategic review of its Kentucky assets and expects to conclude that review by the end of 2021.[202] AEP has not, contrary to Mr. Kollen's characterization, "made the decision to divest the Company;"[203] it is unknown at this time whether the strategic review will result in a sale of Kentucky Power.[204] As Mr. Mattison explained, it would be inappropriate and potentially harmful for the Commission to base its decision in this case on the possible results of AEP's strategic review.[205] The Commission's decision in this case should be based on known and measurable facts and evidence, as supported by the Company's testimony and economic analysis, not on speculation about a possible future event.[206] The known and measurable facts and evidence demonstrate that Case 1 is the best compliance path for Mitchell.

In addition to being supported by facts and evidence, Case 1 – not Case 2 – actually provides greater future flexibility and optionality for the Company. Authorizing Kentucky Power to construct both CCR and ELG environmental compliance projects "provides greater future flexibility and optionality to the Company to optimize its generation resource

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[201] Kollen Test. at 7.
[202] Mattison Rebuttal Test. at R5.
[203] Kollen Test. at 7.
[204] Mattison Rebuttal Test. at R5.
[205] *Id.*
[206] *Id.*

portfolio."[207] Limiting the Company to construct CCR only and retire Mitchell in 2028, on the other hand, could constrain the Company by potentially creating a capacity shortfall and a tight timeline to determine, obtain approval of, and acquire or construct replacement generation resources.[208] Thus, contrary to Mr. Kollen's assertions, the consideration of flexibility weighs in favor of Case 1, not Case 2.

C. The Company's Cost Recovery, Return on Equity, Tariff E.S., and Accounting Authority Proposals are Reasonable and Should Be Approved.

The Company's cost recovery, Tariff E.S., ROE, accounting, and depreciation proposals, detailed in Section II.E above, are reasonable, cost-effective for compliance with the CCR and ELG Rules, and largely unopposed. The Commission should approve these proposals as requested by Kentucky Power, and it should disregard AG/KIUC's flawed depreciation and cost recovery arguments for the reasons set forth below.

1. AG/KIUC's Depreciation Rate Proposal is Inconsistent with Accounting Guidance, Ratemaking Principles, and Commission Precedent, and it Would Be Harmful to Customers and the Company.

The Commission should reject AG/KIUC Witness Kollen's recommendation that Kentucky Power use the currently-authorized depreciation rates.[209] As an initial matter, Mr. Kollen offers absolutely no basis for his flawed recommendation.[210] The Commission therefore should disregard his unsupported opinion.

Moreover, as Company Witness Whitney explained in rebuttal, Mr. Kollen's recommendation is contrary to Generally Accepted Accounting Principles ("GAAP") and Federal Energy Regulatory Commission ("FERC") general instructions, which "make it clear

[207] *Id.*
[208] *Id.*
[209] Kollen Test. at 27
[210] *Id.*

that assets should be depreciated over their expected remaining lives."[211] The Company's CCR and ELG investments will be separately identifiable in the Company's property accounting records.[212] Accordingly, consistent with GAAP and FERC Code of Federal Regulations, Title 18, the separately-identifiable CCR and ELG environmental compliance investments should be depreciated through 2040 at a rate of 5.86% under Case 1, or through 2028 at a rate of 20% under Case 2, until total Mitchell Plant depreciation rates are updated in a future base rate case.[213]

It is fundamental to cost-of-service ratemaking that the cost of an asset should be recognized over the period that it is used and useful to provide service to customers, and not longer.[214] Depreciating an asset longer than it is expected to be used and useful, as Mr. Kollen advocates, also "improperly shifts the cost of service to customers who will not benefit from the asset."[215] Mr. Kollen's proposal would saddle customers not benefitting from the Mitchell Plant CCR and ELG investment with a significant future bill. It would also significantly delay cash flows to Kentucky Power, harming the Company's already weakened credit metrics and financial health.[216] As Company Witness Whitney explained, not adopting the depreciation rates the Company proposes and instead following the approach AG/KIUC advocate would result in approximately $33 million (or roughly half) of the total expected CCR and ELG NBV remaining

[211] Whitney Rebuttal Test. at R2.

[212] *Id.* at R3.

[213] *Id*. Company Witness Whitney also explained that if the Commission selects Case 2 in these proceedings, resulting in the 2028 closure of Mitchell Plant, the Company would be required, consistent with Accounting Standards Codification 360-10-35-3, to change to the GAAP per books depreciation estimated retirement date for Mitchell from 2040 to 2028. *Id.* at R5. The accounting treatment that would be required to reflect that change is summarized in Ms. Whitney's Rebuttal Testimony. *Id.* at R5-R6.

[214] *Id.* at R2.

[215] *Id.*

[216] Mattison Rebuttal Test. at R4. As detailed below, AG/KIUC Witness Kollen's proposal to extend recovery of the Company's CCR and ELG investments for 25 years through the Decommissioning Rider likewise would harm Kentucky Power's cash flows, credit metrics, and financial health.

in December 2040 for future recovery from customers under Case 1.[217] It would leave approximately $11 million (or nearly 85%) of the total expected CCR investment NBV remaining for customers to pay after December 2028 under Case 2.[218]

The depreciation treatment Mr. Kollen advocates is inconsistent not only with accounting guidelines and with cost-of-service ratemaking principles, but also Commission precedent. In its January 13, 2021 Order in Kentucky Power's most recent base rate case, the Commission denied AG/KIUC's proposal to extend the depreciation period associated with the Rockport Unit 2 SCR, citing "concern regarding the numerous cost deferrals already established for Kentucky Power . . ."[219] It should similarly deny AG/KIUC's depreciation rate proposal in this case.

2. The Commission Should Reject AG/KIUC's Recommendation to Delay Recovery of Mitchell Plant's Remaining Net Book Value through the Decommissioning Rider.

The Commission also should decline AG/KIUC Witness Kollen's suggestion that the Commission "could 'flatten' the recovery of the remaining NBV of the Mitchell units over their prior remaining book lives or an even longer period by using a modified version of the Company's Decommissioning Rider."[220] As Mr. Kollen implicitly recognizes,[221] Kentucky Power is not currently authorized to recover Mitchell Plant investment through the Decommissioning Rider.[222] Rather, as Company Witness Mattison explained, the Company's existing Decommissioning Rider currently only recovers the coal-related retirement costs of Big

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[217] Whitney Rebuttal Test. at R3-R4.

[218] *Id.* at R4.

[219] *Id.*; Order, *In the Matter of: Electronic Application of Kentucky Power Company for (1) a general adjustment of its rates for electric service; (2) approval of tariffs and riders; (3) approval of accounting practices to establish regulatory assets and liabilities; (4) approval of a certificate of public convenience and necessity; and (5) all other required approvals and relief* at 27 (Ky. PSC, Jan. 13, 2021).

[220] Kollen Test. at 24.

[221] *Id.*

[222] *Id.*

Sandy Unit 1, the retirement costs of Big Sandy Unit 2, and other site-related retirement costs that will not continue in use.[223]

As with nearly all of his other proposals, Mr. Kollen provided no evidence or analysis regarding the potential impacts on customers or the Company associated with modifying the Decommissioning Rider as he suggests. It would be inappropriate for the Commission to modify Kentucky Power's Decommissioning Rider in this proceeding, where no record has been developed regarding those impacts or any other relevant considerations. Moreover, that a similar rider mechanism may be modified if the Commission approves a settlement in other proceedings involving other utilities does not justify a similar change to the Decommissioning Rider in this case.[224] Not only has the Commission not yet decided those cases, but the settlement agreement in those two non-Kentucky Power cases represents a bargained for quid pro quo resolving the specific issues of those two cases.[225] Moreover, because there is not a complete identity of parties between those two cases and this case, the interests of the parties (including the utilities) are different.[226] It is self-serving and inappropriate for AG/KIUC, who are settling parties in that proceeding to attempt to impose one of many bargained for terms of that settlement upon Kentucky Power, particularly without a complete evidentiary record regarding the impacts of that proposal on customers or the Company itself.

The evidence that <u>has</u> been presented in this case (although none by Mr. Kollen) demonstrates that AG/KIUC's Decommissioning Rider proposal could be harmful to both customers and the Company. Like the depreciation rate proposal discussed in Section IV.C.1,

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[223] Mattison Rebuttal Test. at R3.
[224] *See* Kollen Test. at 24 (citing settlement agreement filed in Case Nos. 2020-00349 and 2020-00350).
[225] *See* Mattison Rebuttal Test. at R3.
[226] *Id.*

AG/KIUC's Decommissioning Rider proposal could have the effect of shifting the remaining cost of service associated with the remaining Mitchell Plant NBV to customers who will not benefit from that asset, particularly if cost recovery were extended beyond Mitchell Plant's book life as Mr. Kollen suggests.[227] That result would be inconsistent with cost-of-service ratemaking principles.[228] It would also delay cash flows to Kentucky Power, which would be harmful to the Company's credit metrics and financial health:[229] As Company Witness Mattison explained:

> Timely and sufficient cost recovery is required to maintain the cash flows necessary to support a stable investment grade credit rating. Having investment grade credit assures the investment community that the Company can service its current and future debt obligations and enables Kentucky Power to source capital at attractive rates for its customers. Further deterioration of Kentucky Power's cash flows by accepting Mr. Kollen's Decommissioning Rider proposal would result in downgrade pressure on the Company's credit ratings and increased borrowing costs associated with future financing activity.[230]

The Company plans to seek recovery of the remaining Mitchell Plant NBV in a future regulatory proceeding, where it will file a depreciation study, related updates to depreciation rates, and other evidence available at that time in support of that request.[231] It is appropriate for the Commission to address recovery of remaining Mitchell Plant NBV in that future proceeding, when all of the information necessary to do so is available. For all of these reasons, the Commission should reject AG/KIUC's Decommissioning Rider proposal in this case.

V. CONCLUSION

Kentucky Power has demonstrated that completing CCR and ELG compliance work at Mitchell Plant (Case 1) is in the public interest and will provide benefits and savings to

[227] *Id.* at R4.
[228] Whitney Rebuttal Test. at R2.
[229] Mattison Rebuttal Test. at R4.
[230] *Id.*
[231] *Id.*

customers through 2040. The Commission, therefore, should approve the Company's Application and grant the relief requested therein.

Respectfully submitted,

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