COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief.	)))))))))	Case No. 2017-00321

DUKE ENERGY KENTUCKY, INC.'S
BRIEF

Comes now Duke Energy Kentucky, Inc. (Duke Energy Kentucky or Company), by counsel, pursuant to the Commission's March 14, 2018 Order setting forth the procedural schedule for the post-hearing activities in this proceeding, and for its Brief supporting its request for an increase in base electric rates and other relief does hereby respectfully state as follows:

I. Introduction

Duke Energy Kentucky is requesting an increase in its base electric rates for the first time in eleven years. When the Application in this case was filed, Duke Energy Kentucky proposed an increase in base rates of $48,646,222,[1] which would amount to an approximate 17.1% increase ($15.17 per month) for a residential customer consuming 1,000 kilowatt hours (kWh) of electricity.[2] However, during the pendency of this case, the United States Congress enacted the

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[1] *See* Sarah Lawler Direct Testimony (Lawler Direct), p. 5 (filed Sep. 1, 2017).

[2] *See* Application, ¶ 9.

Tax Cuts and Jobs Act (Tax Act),[3] which lowered the federal corporate income tax rate from 35% to 21% and effected other changes in federal tax law that are relevant to the Company's rates.[4] In light of the Tax Act and other downward adjustments voluntarily made by the Company, the total requested increase in electric base rates has been reduced to $30,119,059,[5] which would amount to an approximate 11% ($9.73) increase for a typical residential customer consuming 1,000 kWh of electricity each month.[6]

In addition to the increase in base electric rates, Duke Energy Kentucky is also proposing clarifying language changes to several tariffs and service regulations, as well as to establish and implement three new discrete surcharge mechanisms to recover: (1) incremental distribution capital investments for Commission-approved multi-year initiatives intended to maintain, enhance, and improve distribution system integrity and reliability for customers; (2) volatile costs and credits, incremental to what is in base rates, for certain transmission expenses that are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) and for which the Company has very little control; and (3) environmental compliance costs for the Company's East Bend Generating Station (East Bend).[7]

In addition to updating and amending several other tariffs, the Company also seeks to recover, through amortization, certain previously-approved regulatory assets, including: (1) storm restoration expenses resulting from Hurricane Ike; (2) research and development investments; (3) incremental operational and maintenance (O&M) and incremental depreciation expense related to the acquisition of the entirety of East Bend; and (4) Advanced Metering Infrastructure (AMI)

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[3] *See* Tax Cuts and Jobs Act, H.R. 1, Public Law 115-97, 131 Stat. 2054 (Dec. 22, 2017).

[4] *See* Stephen De May Rebuttal Testimony (De May Rebuttal). p. 6 (filed Feb. 14. 2018).

[5] *See* Sarah Lawler Rebuttal Testimony, Errata Sheet (filed Mar. 2, 2018).

[6] *See* Company Response to Staff Post-Hearing DR-01-009, Schedule N, p. 1.

[7] *See* Application, ¶ 10.

deployment related expenses.[8] In addition, the Company seeks to amortize its costs of presenting this case.

A rate case, by design, is intended to provide thorough and thoughtful consideration to each facet of a proposed change in a utility's rates. This case has proven to be no exception. The Company is grateful for the professional and purposeful attention given to its Application by the Commission, Staff, and intervenors, and the Company appreciates the sincere and passionate public comments which have been filed herein. The following summation of the positions, arguments and policies reflects the hard work of all those who have contributed to the case from all perspectives. And, with this as the premise underlying what is to follow, the Company respectfully now pleads its case, to wit:

II. Background

A. Overview of Duke Energy Kentucky

Duke Energy Kentucky is a Kentucky corporation with its principal office and principal place of business at 139 East Fourth Street in Cincinnati, Ohio.[9] The Company's local office in Kentucky is at the Duke Energy Envision Center, located at 4580 Olympic Boulevard, Erlanger, Kentucky.[10] Duke Energy Kentucky was originally incorporated in the Commonwealth of Kentucky on March 20, 1901, and attests that it is currently in good standing in the Commonwealth.[11]

Duke Energy Kentucky is a wholly owned subsidiary of Duke Energy Ohio, Inc. (Duke Energy Ohio), which is itself a wholly owned subsidiary of Cinergy Corporation, which in turn is

[8] *See* Application. ¶ 11.

[9] *See id.*, ¶ 1.

[10] *See id.*, ¶ 1.

[11] *See id.*, ¶ 3.

owned by Duke Energy Corporation – one of the largest utilities in the country.[12] In total, Duke Energy Corporation serves approximately 7.4 million electric customers and over 1.5 million natural gas customers throughout its seven state territory that includes Kentucky, Ohio, Indiana, Florida, North Carolina, South Carolina and Tennessee.[13] Duke Energy Kentucky interacts with its affiliated utilities pursuant to a series of Commission-approved agreements,[14] and the Company provided a copy of its Cost Allocation Manual (CAM) as part of its filing.[15]

Duke Energy Kentucky's customers benefit from the economies of scale and accumulation of knowledge and expertise that this affiliation provides.[16] In fact, the Edison Electric Institute recently reported that Duke Energy Kentucky has the lowest residential rates of any investor-owned utility in Kentucky and the sixth lowest residential rates of any investor-owned utility in the nation.[17] The national average rate for residential electric customers is approximately 46% higher than Duke Energy Kentucky's while the national average commercial electric customer rate is approximately 38% higher.[18] The Company's own data indicates that its non-production O&M expense has trended well below the consumer price index of inflation since the Company's last rate case.[19]

The Company at all times seeks to maintain its financial strength and flexibility, including its strong investment-grade credit ratings, thereby ensuring reliable access to capital on reasonable

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[12] *See* James P. Henning Direct Testimony (Henning Direct), p. 5 (filed Sep. 1, 2017).

[13] *See id.*, p. 5.

[14] *See* Jeffrey R. Setser Direct Testimony (Setser Direct), pp 3-15 (filed Sep. 1, 2017).

[15] *See* Application, ¶ 14, Volume 20; *see also* Setser Direct, pp. 16-24 (discussing the Company's cost allocation protocols).

[16] *See* Henning Direct, pp. 6-7.

[17] *See id.*, p. 28; Duke Energy Kentucky Hearing Exhibit 6, p. 37.

[18] *See* Henning Direct, p. 28.

[19] *See id.*, p. 16.

terms.[20] Financial strength and access to capital are necessary for Duke Energy Kentucky to provide cost-effective, safe, and reliable service to its customers. Specific targets that support financial strength and flexibility include: 1) maintaining an equity component of the capital structure that is within the rating agencies' guidelines for Duke Energy Kentucky's credit rating; 2) maintaining strong credit quality; 3) ensuring timely recovery of prudently-incurred costs; 4) maintaining sufficient cash flows to meet obligations; and 5) maintaining a sufficient return on equity to fairly compensate shareholders for their invested capital.[21] The ability to attract capital (both debt and equity) on reasonable terms is vitally important to the Company and its customers, and each of these targets help the Company to meet its overall financial objectives.[22]

1. Customers/Service Territory

Duke Energy Kentucky is a utility engaged in the gas and electric business. Duke Energy Kentucky purchases, sells, stores and transports natural gas in Boone, Bracken, Campbell, Gallatin, Grant, Kenton and Pendleton Counties, Kentucky,[23] serving approximately 98,200 customers.[24] Duke Energy Kentucky also generates electricity, which it distributes and sells in Boone, Campbell, Grant, Kenton and Pendleton Counties.[25] The Company has approximately 140,600 electric customers.[26]

2. Generation, Transmission and Distribution Facilities

Prior to 2006, Duke Energy Kentucky purchased 100% of its power needs from Duke Energy Ohio. However, the Company received Commission approval to acquire its own

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[20] *See* John L. Sullivan, III, Direct Testimony (Sullivan Direct), p. 3 (filed Sep. 1, 2017).

[21] *See* Sullivan Direct, p. 3.

[22] *See id.*, p. 3.

[23] *See* Application, ¶ 2.

[24] *See* Henning Direct, p. 4.

[25] *See* Application, ¶ 2.

[26] *See* Henning Direct, p. 4.

generating assets in Case No 2003-00252.[27] The acquisition of these units was completed on January 25, 2006.[28] Duke Energy Kentucky recently brought online three small solar facilities having an aggregate capacity of 7 megawatts (MWs).[29] The bulk of its recent and current generation facilities are located at the East Bend Generating Station, Woodsdale Generating Station and Miami Fort Generating Station. The Company's generation needs are reviewed through the Company's integrated resource planning (IRP) process.[30]

a. East Bend Generating Station

East Bend is a 648 MW (nameplate rating) coal-fired base load unit located along the Ohio River in Boone County, Kentucky.[31] East Bend was commissioned in 1981 and the Company now owns 100% of the station, having completed the 2014 purchase of the 31% interest held by The Dayton Power and Light Company (DP&L).[32] The net rating for East Bend (the net amount of power that the Company can dispatch from the plant after some portion of the gross power output is used to power the plant machinery) is 600 MW.[33] East Bend was originally planned for up to four coal-fired units but only one unit (Unit 2) was constructed.[34] The station has river facilities to allow barge deliveries of coal and lime and is designed to burn eastern bituminous coal.[35] East Bend achieved an average net plant heat rate of 10,889 Btu/kWh for calendar year 2016.[36] The

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[27] *In the Matter of the Application of the Union Light, Heat and Power Company for a Certificate of Public Convenience to Acquire Certain Generation Resources and Related Property; for Approval of Certain Purchase Power Agreements; For Approval of Certain Accounting Treatment; and Approval of Deviation from Requirements of KRS 278.2207 and 278.2213(6)*, Order, Case No 2003-00252 (Ky. P.S.C. Dec. 5, 2003).

[28] *See* Application, ¶ 30.

[29] *See* Henning Direct, p. 20.

[30] *See* John A. Verderame Direct Testimony (Verderame Direct), pp. 5-9 (filed Sept. 1, 2017).

[31] *See* Joseph A. Miller, Jr., Direct Testimony (Miller Direct), p. 3 (filed Sep. 1, 2017).

[32] *See id.*

[33] *See id.*

[34] *See id.*

[35] *See id.*

[36] *See id.*, p. 4.

station's electrical output is directly connected to the Duke Energy Midwest (consisting of Kentucky and Ohio) 345 kilovolt (kV) transmission system.[37]

The Company has made significant investment in its environmental infrastructure at East Bend. The major pollution control features include a high-efficiency hot side electrostatic precipitator, a lime-based flue gas desulfurization (FGD) system, and a selective catalytic reduction control (SCR) system designed to reduce nitrogen oxide (NO_x) emissions by 85%.[38] The FGD system was upgraded in 2005 to increase the sulfur dioxide (SO_2) emissions removal to an average of 97%.[39] In 2015, Duke Energy Kentucky commenced construction on a new landfill to replace the 30-year old landfill that was reaching capacity.[40] In 2017, the Company received Commission authorization to convert East Bend's wet ash handling system to a dry ash disposal system to comply with the CCR Final Rule.[41] The Company also gained approval to close its current ash pond, repurpose it and construct a new process water system in order to comply with both the CCR Final Rule and the Steam Electric Effluent Limitation Guidelines Final Rule (ELG Rule).[42]

Historically, approximately 80% of the ash produced at East Bend was dry fly ash.[43] As part of the disposal process, that material is mixed with spent scrubber slurry and lime to make a stable material called Poz-O-Tec.[44] The Poz-O-Tec mixture sets up much like concrete and it is disposed of in the onsite landfill. The remaining 20% of ash is bottom ash that was treated and

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[37] *See id.*

[38] *See id.*

[39] *See id.*

[40] *See* Henning Direct, p. 19.

[41] *See id.*

[42] *See id.*, pp. 19-20.

[43] *See* Miller Direct, p. 4.

[44] *See id.*, pp. 4-5.

stored in the onsite ash pond.[45] The East Bend ash pond has also historically supported East Bend's operation by providing dilution, settling and/or retention functions for other power plant process water flows, including, but not limited to, low volume wastewater, coal pile run-off, landfill leachate, and FGD wastewater.[46] Duke Energy Kentucky utilizes a water sluice process to efficiently transport the bottom ash to its pond.[47] Together the pond and landfill are used for the storage and disposal of waste products resulting from the Company's FGD system and other waste material.[48]

There are two permitted landfills at East Bend, the East Landfill, which is nearing capacity, and its replacement, the West Landfill. The East Landfill is comprised of approximately 162 acres and has been in place since East Bend was constructed in 1981.[49] The East Landfill's original construction pre-dated the CCR Final Rule's effective date but will eventually be closed in a manner that complies with the CCR Final Rule.[50] The East and West Landfills are permitted to receive various forms of waste, including, but not limited to, FGD waste, fly ash, and bottom ash (Generator Waste), from a number of generating sources, including those generating stations currently owned and/or operated by Duke Energy Kentucky and others.[51] The Landfills are permitted to receive Generator Waste from sources other than East Bend to ensure that Duke Energy Kentucky has sufficient dry fly ash material available to make the Poz-O-Tec byproduct necessary to operate the station's FGD handling process.[52] This permitting for multiple stations is

[45] *See id.*, p. 5.

[46] *See id.*

[47] *See id.*

[48] *See id.*

[49] *See id.*

[50] *See id.*

[51] *See id.*, pp. 5-6.

[52] *See id.*, p. 6.

a significant benefit to the Company as Duke Energy Kentucky, at times, does not produce sufficient quantities of ash to make the Poz-O-Tec.[53] The West Landfill design and estimated life contemplated the likely eventual need to convert East Bend to a 100% dry ash.[54]

b. Woodsdale Generating Station

Woodsdale is a six-unit, simple cycle, combustion turbine (CT) station located in Butler County, Ohio, just north of Cincinnati, with a collective net winter rating of 564 MW and a net summer rating of 462 MW.[55] Woodsdale was designed to provide peaking service and to have black start and dual fuel capability.[56] Black start capability means that the station has the ability to initiate a recovery of a substantial portion of load without relying on energy from outside sources if the regional grid experiences a blackout.[57] The Company's six units at Woodsdale will have backup fuel oil systems in place in the Spring of 2019.[58] Woodsdale is connected to the Texas Eastern Transmission Company (TETCO) interstate pipeline that transports the natural gas to supply the station.[59] Woodsdale's design as a peaking unit with low capacity factors does not economically support acquiring firm natural gas transportation through the available natural gas interstate pipelines.[60]

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[53] *See id.*

[54] *See id.*

[55] *See id.*, p. 12.

[56] *See id.*

[57] *See id.*

[58] *See* Company Response to Staff DR-02-077; Miller Direct, p. 14; *see also In the Matter of: Electronic Application of Duke Energy Kentucky, Inc. For a Certificate of Public Convenience and Necessity for Construction of Number 2 Distillate Fuel Oil System at the Company's Woodsdale Natural Gas-Fired Generating Station*, Order, Case No. 2017-00186 (Ky. P.S.C. Dec. 21, 2017).

[59] *See* Miller Direct, p. 13.

[60] *See id.*, pp. 13-14.

c. Miami Fort 6 Generating Station

Miami Fort 6 is a 168 MW (nameplate rating) coal-fired base/intermediate load unit located at Miami Fort Station along the Ohio River in Hamilton County, Ohio, that was commissioned in 1960.[61] The net rating for Miami Fort 6 is 163 MW. Miami Fort 6 was retired effective June 1, 2015, consistent with the Commission's Order in Case No. 2014-00201,[62] as a result of the enactment of the Environmental Protection Agency's (EPA) Mercury Air Toxics Standard (MATS) Rule.[63]

At the time of its retirement, Miami Fort Unit 6 was one of three operating coal-fired units at the Miami Fort Generating Station.[64] While Duke Energy Kentucky wholly owns Miami Fort Unit 6, Miami Fort Units 7 and 8 are now jointly owned by Dynegy Inc. (Dynegy) (64%) and DP&L (36%). Duke Energy Ohio sold its interests in the Miami Fort Generating Station to Dynegy several years ago.[65] As the current majority station owner, Dynegy operated Miami Fort Unit 6 on behalf of Duke Energy Kentucky until the unit's retirement, and still provides basic maintenance and upkeep services at the station until its decommissioning or disposal.[66] Dynegy provides these services in accordance with an operating agreement that was approved by the Commission in Case

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[61] *See id.*, p. 14.

[62] *See In the Matter of: Application of Duke Energy Kentucky, Inc. For (1) A Certificate of Public Convenience and Necessity Authorizing the Acquisition of The Dayton Power & Light Company's 31% Interest in the East Bend Generating Station; (2) Approval of Duke Energy Kentucky, Inc.'s Assumption of Certain Liabilities in Connection with the Acquisition; (3) Deferral of Costs Incurred as Part of the Acquisition; and (4) All Other Necessary Waivers, Approvals, and Relief*, Order, Case No. 2014-00201 (Ky. P.S.C. Dec. 4, 2014).

[63] *See* Miller Direct, pp. 14-15; Verderame Direct, p. 15.

[64] *See* Miller Direct, p. 15.

[65] *See id.*, p. 15.

[66] *See id.*, p. 15.

No. 2014-00287.[67] As the unit owner, Duke Energy Kentucky has taken and will continue to take appropriate steps to decommission Miami Fort 6 following the plant's retirement.[68]

d. Transmission Facilities

Although it owns approximately 107 circuit-miles of 69 kV transmission lines,[69] Duke Energy Kentucky is a transmission dependent utility.[70] The Company relies upon the bulk transmission system of its parent company, Duke Energy Ohio and that of neighboring utilities in PJM Interconnection LLC (PJM). Transmission is thus a significant expense for the Company that is largely outside of its control.[71] The Company's transmission infrastructure is supervised by the Company's Transmission Asset Management Group.[72]

e. Distribution Facilities

Duke Energy Kentucky owns and operates approximately 2,900 circuit miles of distribution lines throughout its service territory.[73] The Company recently began deploying an AMI system which will significantly improve the Company's ability to operate its distribution system and allow for the deployment of new technologies.[74]

3. Community Involvement

Duke Energy Kentucky is an active part of the vibrant northern Kentucky community. The Company is heavily involved in economic development efforts based upon the fact that "access to

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[67] *See In the Matter of: Duke Energy Kentucky, Inc., for Authorization to Enter into a Transaction and Agreement with an Affiliate or in the Alternative, Approval of Deviations from the Requirements of KRS 278.2213(6)*, Order, Case No. 2014-00287 (Ky. P.S.C. Jan. 12, 2015).

[68] *See* Miller Direct, p. 16; Company Response to AG DR-01-027.

[69] *See* Henning Direct, p. 4.

[70] *See* Application, ¶ 37.

[71] *See id.*, ¶ 38.

[72] *See* Company Response to Staff DR-01-012.

[73] *See* Henning Direct, p. 4.

[74] *See id.*, pp. 20-21.

affordable, reliable power is a critical factor in a company's decision about where to locate its facilities."[75] Duke Energy Kentucky was named by *Site Selection* as one of the Top 10 Utilities in Site Selection for North America for the eighteenth consecutive year.[76] The Company conservatively estimates that its cooperative efforts have helped create nearly 20,000 jobs in Northern Kentucky, and attract more than $2 billion of capital investment since 2006.[77] The Company's economic development efforts are funded by shareholders, not customers.[78]

The Company is also very involved in charitable endeavors. Since 2006, Duke Energy Kentucky and the Duke Energy Foundation have contributed approximately $4 million in shareholder dollars to charitable organizations in Kentucky.[79] The Company sponsored fifteen volunteer events in 2016 that resulted in over 700 hours of time being donated by Company employees, family members and retirees.[80]

4. Customer Satisfaction

Duke Energy Kentucky places great value on its relationships with customers. It currently has several points of interaction with customers, including contact centers, a business service center, pay agents, an automated phone service, enhanced web functionality for online service and periodic focus groups for small and medium-sized businesses.[81] The Company offers four

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[75] *Id.*, p. 7.

[76] *See id.*, p. 8.

[77] *See id.*, p. 9. The Company works closely with many community development organizations, including: Northern Kentucky Tri-ED; Northern Kentucky Chamber of Commerce; Kentucky Association of Economic Development; REDI; Cintrifuse; Cincinnati USA Regional Chamber of Commerce; Cincinnati Business Committee, Economic Development; Cincinnati Center City Development Corporation; Greater Cincinnati Chinese Chamber of Commerce; European American Chamber of Commerce; and Kentucky Chamber of Commerce. *See id.*

[78] *See* Company Response to Staff DR-03-012.

[79] *See* Henning Direct, p. 10.

[80] *See id.*

[81] *See id.*, pp. 10-11.

different programs to help customers manage their bills,[82] and three options for making payments convenient.[83] Duke Energy Kentucky is planning a massive overhaul of its Customer Information System in the short-term that will allow it to offer even greater functionality with more flexibility and higher efficiency.[84]

The Company's ability to provide its customers with flexible energy management and bill payment options has consistently resulted in Duke Energy Kentucky receiving high marks from J.D. Power studies and internal surveys measuring customer satisfaction. In fact, the 2017 J.D. Power Customer Satisfaction Survey showed that Duke Energy Midwest's overall satisfaction scores outperformed both the Midwest Region's average scores and the large utility average.[85] Moreover, through the first six months of 2017, the Company's internal Fastrack surveys have measured customer satisfaction in several key areas. The Fastrack surveys have shown that 90% of Duke Energy Kentucky's residential customers were highly satisfied with their overall service initiation experience; 97% of residential customers were highly satisfied with their overall Outdoor Lighting Repair experience; 85% of residential customers were highly satisfied with their overall billing experience and 74% of residential customers were highly satisfied with their outage/restoration experience.[86] The survey responses indicated that, while customers generally have a good experience when interacting with Duke Energy Kentucky, it is important for the Company to focus upon improving customers' experience with regard to avoiding outages and minimizing restoration times. The Company's AMI roll-out and its proposed Rider DCI

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[82] These programs include: Budget Billing; Adjusted Due Date; Extended Payment Agreements; and Home Energy Assistance. *See id.*, p. 11.

[83] The Company currently offers Speedpay, e-bill and Payment Advantage in addition to the traditional U.S. Postal Service payment option. *See id.*

[84] *See id.*, p. 18.

[85] *See id.*, pp. 12-13.

[86] *See id.*, pp. 14-15.

(discussed below) are both key elements of Duke Energy Kentucky's continued efforts to improve customers' experiences.

B. Developments Since Duke Energy Kentucky's Last Rate Case

Duke Energy Kentucky's base electric rates were last increased in an Order entered on December 21, 2006, in Case No. 2006-00172, and became effective on January 2, 2007.[87] Since then, the Company has made over $600 million in new investments without seeking a base rate increase.[88] Through effective management and aggressive cost controls,[89] Duke Energy Kentucky has delayed the need for an increase in base rates for over eleven years.[90] However, Duke Energy

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[87] *See In the Matter of the Application of the Union Light, Heat and Power Company D/B/A Duke Energy Kentucky for an Adjustment of Electric Rates*, Order, Case No. 2006-00172 (Ky. P.S.C. Dec. 21, 2006); Don E. Wathen, Jr., Direct (Wathen Direct), p. 3 (filed Sep. 1, 2017).

[88] *See* Henning Direct, p. 29; Company Response to Staff DR-02-017.

[89] As an example, the Company's non-production O&M expense has remained relatively flat for the last decade despite inflationary pressures. *See* Wathen Direct, p. 7.

[90] To achieve cost-savings, the Company has undertaken several programs since 2006, including: Next Gen and the Duke Production System to improve generation efficiency; transmission and distribution contractor management efforts; continuous workforce improvement workflow activities in the Company's distribution function; and corporate cost reductions through the elimination of redundant processes and workforce planning. *See* Company Response to Staff DR-01-030c. In contrast, other Kentucky-based investor owned utilities have had multiple rate cases over the same period. *See e.g. In the Matter of: Electronic Application of Kentucky Power Company for (1) A General Adjustment of its Rates for Electric Service; (2) An Order Approving its 2017 Environmental Compliance Plan; (3) An Oder Approving its Tariffs and Riders; (4) An Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities; and (5) An Order Granting all Other Required Approvals and Relief*, Order, Case No. 2017-00179 (Ky. P.S.C. Jan. 18, 2018); *In the Matter of: Application of Kentucky Power Company for: (1) A General Adjustment of its Rates for Electric Service; (2) An Order Approving its 2014 Environmental Compliance Plan; (3) An Order Approving its Tariffs and Riders; and (4) An Order Granting all Other Required Approvals and Relief*, Order, Case No. 2014-00396 (Ky. P.S.C. June 22, 2015); *In the Matter of: Application of Kentucky Power for a General Adjustment of Electric Rates*, Order, Case No. 2013-00197 (Ky. P.S.C. Nov. 22, 2013). (This case was withdrawn by Kentucky Power as part of the Mitchell Settlement Agreement); *In the Matter of: Application of Kentucky Power Company for a General Adjustment of Electric Rates*, Order, Case No. 2009-00459 (Ky. P.S.C. June 28, 2010); *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Electric Base Rates*, Order, Case. No. 2008-00251 (Ky. P.S.C. Feb. 5, 2009); *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates*, Order, Case No. 2009-00548 (Ky. P.S.C. July 30, 2010); *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of its Electric Rates*, Order, Case No. 2012-00221 (Ky. P.S.C. Dec. 20, 2012); *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of its Electric Rates*, Order, Case No. 2014-00371 (Ky. P.S.C. June 30, 2015); *In the Matter of: Electronic Application of Kentucky Utilities Company for an Adjustment of its Electric Rates and for Certificates of Public Convenience and Necessity*, Order, Case. No. 2016-00370 (Ky. P.S.C. June 22, 2017) *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Base Rates*, Order, Case No. 2008-00252 (Ky. P.S.C. Feb. 5, 2009); *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Base Rates*, Order, Case No. 2009-00549 (Ky. P.S.C. July 30, 2010); *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates, A Certificate of Public Convenience and*

Kentucky's earned rate of return on capitalization obtained from its current electric operations has fallen to 2.85%, which is inadequate to enable the Company to continue providing safe, reasonable and reliable service to its customers and is insufficient to afford Duke Energy Kentucky a reasonable opportunity to earn a fair return on its investment property that is used to provide such service while attracting necessary capital at reasonable rates.[91] The erosion in the Company's return is even more noteworthy in light of the many significant developments and efficiencies enabled in Duke Energy Kentucky's business over this same period of time.

On January 1, 2012, Duke Energy Kentucky made the transition from being a member of the Midwest Independent System Operator to becoming a member of PJM.[92] The Company operates in the PJM market as a Fixed Resource Requirement (FRR) entity, meaning that it must support its own load obligations with dedicated generation resources.[93] As an FRR entity, Duke Energy Kentucky must secure and commit unit-specific generation resources (either physical generation assets or demand-side management resources) to meet the full load capacity requirements for all its customers in advance of the PJM base residual auction (BRA) through its FRR Plan.[94] The FRR Plan is forward-looking in that it covers the Delivery Year (June through May) three years into the future.[95] Thus, for its most recent FRR plan submitted in 2017, Duke Energy Kentucky must own or contract and commit the unit specific generation resources

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Necessity, Approval of Ownership of Gas Service Lines and Riders, and a Gas Line Surcharge, Order. Case No. 2012-00222 (Ky. P.S.C. Dec. 20, 2012); *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates,* Order, Case No. 2014-00372 (Ky. P.S.C. June 30, 2015); *In the Matter of: Electronic Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates and for Certificates of Public Convenience and Necessity,* Order, Case No. 2016-00371 (Ky. P.S.C. June 22, 2017).

[91] *See* Application, ¶ 11.

[92] *See id.*; Wathen Direct, p. 17.

[93] *See* Verderame Direct, p. 12.

[94] *See id.*

[95] *See id.*

necessary to satisfy its forecasted load requirements for the period from June 1, 2020, through May 31, 2021.[96] Accordingly, the Company has similar performance risk to other Reliability Pricing Model (RPM) auction participants in the PJM capacity market, but less flexibility as an FRR entity to adjust its plan to account for changes in resource requirements.[97] Moreover, FRR entities are subject to a different methodology for calculating reserves.[98]

On May 31, 2015, MATS forced the Company to retire its smaller coal-fired generating unit – Miami Fort 6.[99] The loss of 163 MWs was significant to Duke Energy Kentucky. However, the Company was able to replace the lost capacity by acquiring the balance of the East Bend capacity owned by DP&L.[100] The acquisition of 186 MWs of reliable capacity for only $12.4 million was a critical component of the Company's continued ability to satisfy its obligations as an FRR entity in PJM.[101] While East Bend is a reliable and reasonable cost unit, the increased reliance on this unit and the consequent decrease in resource diversity translates into a different exposure to short-term power prices when the station is not operating due to either forced or scheduled maintenance outages.[102]

Duke Energy Kentucky has been involved in three significant mergers. In 2006, Cinergy Corporation merged with Duke Energy Corporation.[103] As stated earlier, this merger made the combined entity one of the largest utilities in the country. In 2012, Duke Energy Corporation

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[96] *See id.*

[97] *See id.*, p. 13.

[98] *See id.*, p. 5.

[99] *See* Wathen Direct, p. 5.

[100] *See* Henning Direct, p. 19.

[101] *See id.*, p. 16; Wathen Direct, p. 4; Verderame Direct, pp. 15-16.

[102] *See* Verderame Direct, p. 16.

[103] *See* Henning Direct, p. 5.

merged with Progress Energy, Inc.[104] Then, in 2016, Duke Energy Corporation acquired Piedmont Natural Gas Company, Inc., which significantly expanded the scope and scale of Duke Energy Corporation's natural gas operations.[105] These mergers have increased the intellectual capital and expertise available throughout the enterprise.

While the Company has marginally increased the number of customers within its service territory since its last rate case, any gains in load growth attributable to increased customer numbers have been largely offset by energy efficiency efforts and changing customer behaviors.[106] Total retail sales projected for the test year reflect only about 1.6% growth over the eleven-year period since the Company's last rate case.[107] In addition the Great Recession of 2008-2009 had a discernable negative impact in the rate of growth nationally and throughout Kentucky. Despite this, the Company has been able to reduce its cost of capital.[108] Duke Energy Kentucky has embraced each of the challenges and opportunities afforded by these events over the past eleven years, but its current rates are no longer sufficient to enable the Company to furnish adequate, efficient and reasonable service and have the opportunity to earn a fair rate of return on investments.[109]

C. Procedural History

Duke Energy Kentucky filed its Notice of Intent to file an application seeking an increase in its electric base rates and for other relief on August 2, 2017.[110] As set forth therein, the Company

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[104] *See id.*, p. 17.

[105] *See id.*, p. 5.

[106] *See* Henning Direct, p. 21.

[107] *See* Wathen Direct, pp. 7-8.

[108] The Company is proposing a 10.3% return on equity in this case, which is well below the 11.5% requested in its 2006 rate case. Likewise, the Company's cost of debt has decreased from 5.707% to 4.243%. *See* Wathen Direct, p. 8; *see also* Sullivan Direct, p. 12.

[109] *See* Henning Direct, p. 21.

[110] *See* Notice of Intent, Case No. 2017-0321 (filed Aug. 2, 2017).

proposed to base its proposed rate increase upon a fully forecasted test period consisting of the twelve months ending March 31, 2019.[111] The Notice of Intent was served upon the Attorney General (AG).

The Company filed its Application on September 1, 2017 and gave the necessary public notice associated therewith via publication in the appropriate newspapers of general circulation within its service territory.[112] Notice of the rate filing was also posted at the Company's place of business and on its website and was also timely provided to the AG.[113] The Application utilized a forward-looking test period for the twelve months ending March 31, 2019, which corresponds to the first twelve calendar month period the proposed rates would be in effect following the six-month suspension of the proposed rates.[114] The filing complies with all previous commitments made by the Company relating to ratemaking and cost recovery.[115] Twenty-two witnesses provided direct testimony to support the Application. Following the cure of filing deficiencies, the Application was deemed filed on September 15, 2017.

The Commission suspended the Company's proposed rates from taking effect and established a procedural schedule by way of an Order entered September 27, 2017.[116] The Commission also granted intervention to the AG,[117] Kentucky Industrial Utility Customers, Inc. (KIUC),[118] the Kentucky School Boards Association (KSBA),[119] the Kroger Company (Kroger)[120]

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[111] *Id.*

[112] *See* Application, ¶ 16; Proof of Publication of Public Notice (filed Oct. 16, 2017).

[113] *See* Application, ¶¶ 17 – 18.

[114] *See id.*, ¶ 22.

[115] *See* Wathen Direct, pp. 36-38.

[116] *See* Order, Case No. 2017-00321 (Ky. P.S.C. Sep. 27, 2017).

[117] *See* AG's Motion to Intervene (filed Aug. 30, 2017); Order, Case No. 2017-00321 (Ky. P.S.C. Sep. 5, 2017).

[118] *See* KIUC's Motion to Intervene (filed Oct. 13, 2017); Order, Case No. 2017-00321 (Ky. P.S.C. Oct. 23, 2017).

[119] *See* KSBA's Motion to Intervene (filed Oct. 9, 2017); Order, Case No. 2017-00321 (Ky. P.S.C. Oct. 17, 2017).

[120] *See* Kroger's Motion to Intervene (filed Sep 13, 2017); Order, Case No. 2017-00321 (Ky. P.S.C. Oct. 17, 2017).

and Northern Kentucky University (NKU).[121] The Kentucky League of Cities filed an untimely motion for leave to intervene, which was denied.[122] In all, Duke Energy Kentucky responded to four sets of Requests for Information from the Commission, two sets of Requests for Information each from the AG, Kroger, KSBA, and NKU, and one set of Requests for Information from KIUC.

Several of the intervenors also sponsored expert witnesses as part of the proceeding. The AG presented testimony from: (1) Mr. Lane Kollen on various matters involving the Company's proposed revenue requirement and capitalization; (2) Mr. Richard Baudino on issues relating to the allowed rate of return; and (3) Mr. Glenn Watkins on issues pertaining to the Company's cost of service study and proposed customer charge and fixed bill program. KSBA sponsored testimony provided by Mr. Ronald Willhite on various tariff issues relating to schools. NKU offered testimony from Mr. Brian Collins on the Company's proposed class cost of service study, the proposed class revenue allocation and the Company's proposed Rider DCI and Rider FTR, while Kroger offered the testimony of Mr. Justin Bieber on the Tax Act, the Company's class revenue allocation and Rider DCI. Commission Staff thereafter propounded Requests for Information to the AG, NKU and KSBA. Duke Energy Kentucky also tendered Requests for Information to the AG, NKU, KSBA and Kroger. Duke Energy Kentucky filed rebuttal testimony from twelve witnesses on February 14, 2018.[123]

The Commission issued an Order on January 5, 2018, setting a formal hearing on Duke Energy Kentucky's Application for March 6, 2018. Prior to the formal hearing, however, a public comment hearing was held at Boone County High School in Florence, Kentucky, on February 8,

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[121] *See* NKU's Motion to Intervene (filed Oct. 12, 2017); Order, Case No. 2017-00321 (Ky. P.S.C. Oct. 23, 2017).

[122] *See* Kentucky League of Cities' Motion to Intervene (filed Oct. 17, 2017); Order. Case No. 2017-00321 (Ky. P.S.C. Oct. 24, 2017).

[123] On March 5, 2018, Duke Energy Kentucky filed corrected rebuttal testimony from two of its witnesses, Mr. William Don Wathen, Jr. and Ms. Sarah Lawler. AG witness Mr. Kollen also filed a correction to his testimony on March 6, 2018.

2018.[124] The Company filed a copy of its Request for Publication of Hearing Notice on February 8, 2018, and filed the Proof of Publication of Hearing Notice on March 2, 2018. A formal hearing was held on three consecutive days from March 6 – 8, 2018, at the Commission's offices in Frankfort. In all, thirty witnesses took the stand on behalf of Duke Energy Kentucky and the intervenors. Following the hearing, Duke Energy Kentucky responded to additional Post-Hearing Requests for Information from Commission Staff, KSBA and the AG. In all, Duke Energy Kentucky responded to 832 separate written questions, including subparts, from Commission Staff and intervenors. With the filing of this Brief, the case now stands submitted for a final decision.

III. Argument

A. Jurisdiction and Standards of Review

It is firmly established that "the regulation of public utilities has and does serve a public purpose. It has a substantial relation to the public welfare, safety and health and, in a real degree, promotes these objects."[125] The Commission is a creature of statute and has only such powers as granted by the General Assembly.[126] The Commission's jurisdiction is therefore limited to the "rates" and "service" of the Company.[127] As the Kentucky Supreme Court has stated, "rates are merely the means designed for achieving a predetermined objective, which in this instance was

[124] *See* Public Comment Hearing Video (Feb. 8, 2018).

[125] *City of Florence v. Owen Elec. Co-op., Inc.*, 832 S.W.2d 876, 882 (Ky. 1992).

[126] *See Boone Co. Water and Sewer District v. Public Service Comm'n*, 949 S.W.2d 588, 591 (Ky. 1997); *Simpson County Water Dist. v. City of Franklin*, 872 S.W.2d 460, 462 (Ky. 1994); *Com., ex rel. Stumbo v. Kentucky Public Service Comm'n*, 243 S.W.3d 374, 378 (Ky. App. 2007); *Cincinnati Bell Telephone Co. v. Kentucky Public Service Comm'n*, 223 S.W.3d 829, 836 (Ky. App. 2007); *Public Service Comm'n v. Jackson County Rural Electric Coop., Inc.*, 50 S.W.3d 764, 67 (Ky. App. 2000).

[127] *See Public Service Comm'n v. Blue Grass Natural Gas Co.*, 197 S.W.2d 765, 768 (Ky. 1946) ("We have held that the jurisdiction of the Public Service Commission is clearly and unmistakably limited to the regulation of rates and service of utilities.") *citing Smith v. Southern Bell Telephone and Telegraph Co.*, 104 S.W.2d 961 (Ky. 1937); *Benzinger, etc., v. Union Light, etc.*, 170 S.W.2d 38 (Ky. 1943); *Peoples Gas Co. of Kentucky v. City of Barbourville*, 165 S.W.2d 567 (Ky. 1942).

how much additional revenue should the Company be allowed to earn."[128] Duke Energy Kentucky is a "utility" as defined in KRS 278.010(3) and is subject to the Commission's jurisdiction pursuant to KRS 278.040.[129] The Company's rates may be increased pursuant to the procedures set forth in KRS 278.180, KRS 278.190, KRS 278.192 and regulations promulgated thereunder.

It is well-established that, "[t]he manifest purpose of the Public Service Commission is to require and insure fair and uniform rates, prevent unjust discrimination, and prevent ruinous competition."[130] In undertaking this purpose, the Commission is affecting the natural property rights of Duke Energy Kentucky.[131] Accordingly, the principles of due process, equal protection and other rights and guarantees afforded under the Constitutions of the United States of America and the Commonwealth of Kentucky apply with full force and effect.[132] The Commission "has no authority to impose a new duty on utilities when that duty has no foundation in law. To do so is an unconstitutional legislative act by the Commission."[133]

The Commission's statutory mandates therefore provide "an integrated, comprehensive system aimed at providing stability and notice to all entities involved in the rate process."[134] In undertaking this process, "the Commission has discretion in working out the balance of interests necessarily involved and...it is not the method, but the result, which must be reasonable."[135]

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[128] *Kentucky Power Co. v. Energy Reg. Comm'n*, 623 S.W.2d 904, 908 (Ky. 1981).

[129] *See Louisville Gas & Elec. Co. v. Dulworth*, 130 S.W.2d 753, 755 (Ky. 1939).

[130] *Simpson County*, p. 464 *citing City of Olive Hill v. Public Service Comm'n*, 203 S.W.2d 68 (Ky. 1947).

[131] *See Bobinchuck v. Levitch*, 380 S.W.2d 233, 236 (Ky. 1964). In contrast, the right to receive utility service is merely a right that may be conferred by statute and lacks the same fundamental constitutional protections. *See Smith v. Southern Bell Tel. & Tel. Co.*, 104 S.W.2d 961, 964 (Ky. 1937).

[132] *See Kentucky Indus. Utility Customers, Inc. v. Kentucky Utilities Co.*, 983 S.W.2d 493, 497 (Ky. 1998).

[133] *Henry v. Parrish*, 211 S.W.2d 418 (Ky. 1948).

[134] *Cincinnati Bell*, pp. 837-38 (Ky. App. 2007) *quoting* KRS 278.160, KRS 278.180, KRS 278.190, KRS 278.260, KRS 278.270 and KRS 278.390.

[135] *Kentucky Indus. Utility Customers*, p. 498 *citing Federal Power Comm'n v. Hope Natural Gas*, 320 U.S. 591 (1944); *see also National-Southwire Aluminum Co. v. Big Rivers Elec. Corp.*, 785 S.W.2d 503, 515 (Ky. App. 1990) *citing Louisville & Jefferson County Met. Swr. Dist. v. Joseph E. Seagram & Sons*, 211 S.W.2d 122 (Ky. 1948).

Kentucky's highest court has commented, "the task of the [Commission] Staff is to conduct investigations to facilitate a thorough exploration of the interests and issues involved. The traditional role of the Staff is 'generally to analyze the evidence and advise the Commission.'"[136] The Commission has considerable discretion to take into account the multitude of factors affecting the rates of a utility. Indeed, the Kentucky Court of Appeals commented upon the breadth of this discretion, stating:

> It is certainly broad enough to consider such things as replacement cost, debt retirement, operating cost, and at least some excess capacity in order to insure continuation of adequate service during periods of high demand and some potential for growth and expansion. It also allows for consideration of whether expansion investments were prudently or imprudently made, and whether a particular utility is investor owned or a cooperative operation. Any of these factors might be extremely significant in varying situations when determining what ultimately would be a fair, just and reasonable rate and would allow for a balancing of interests.[137]

However, the Commission ultimately must approve rates that are "fair, just and reasonable."[138] Accordingly, approved rates must "enable the utility to operate successfully, to maintain its financial integrity, to attract capital and to compensate its investors for the risks assumed…."[139] By contrast, an unreasonable rate "has been construed in a rate-making sense to be the equivalent of confiscatory."[140] It is firmly settled that, among other methods, "[i]n Kentucky a utility company's required net operating income for rate-making purposes is computed by applying its cost of capital to its capital structure….A utility is only permitted to earn a return on

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[136] *Kentucky American Water Co. v. Com. ex rel. Cowan*, 847 S.W.2d 737, 740 (Ky. 1993) (citation omitted).

[137] *National-Southwire*, p. 512.

[138] KRS 278.030(1).

[139] *National-Southwire*, pp. 512-13 *quoting Commonwealth ex rel. Stephens v. South Central Bell Tel. Co.*, 545 S.W.2d 927, 930-31 (1976).

[140] *Public Service Comm'n of Kentucky v. Dewitt Water District*, 720 S.W.2d 725, 730 (Ky. 1986).

debt, equity and preferred, which are sources of capital supplied by investors."[141] In considering the rates to be authorized herein, the Commission must consider both the present *and the future* impact of such rates upon the Company's financial condition.[142] It is critically important for Duke Energy Kentucky to meet its financial objectives and maintain strong credit quality.[143] As the Applicant, the Company bears the burden of proof.[144]

B. The Company's Proposed Increase in Base Rates, as Amended, is Reasonable

1. The Company's Base Period and Forecasted Test Year are Reasonable

The Company utilized a base period consisting of actual data for December 2016 through May 2017 and budgeted data for June through November 2017,[145] allowing it to ultimately use a fully forecasted test period spanning the twelve-month period ending March 31, 2019.[146] In accordance with KRS 278.192(2)(b) the Company filed its updated base period data on January 12, 2018. The Company has made appropriate adjustments based upon known and measurable factors, with data appropriately normalized and annualized.[147]

The Company presented extensive testimony as to the development of its load forecast and normalization calculations,[148] which were incorporated into the data used in the forecasted test

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[141] *Public Service Comm'n of Kentucky v. Continental Tel. Co. of Kentucky*, 692 S.W.2d 794, 796 (Ky. 1985) *citing Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944). KRS 278.290 also allows a utility's earnings to be based upon rate base or other valuation methodologies as well.

[142] *Dewitt Water District*, p. 730 ("When considering the concept of confiscation, the future as well as the present must be considered. It must be determined whether the rates complained of are yielding and will yield a sum sufficient to meet operating expenses.") *citing McCardle v. Indianapolis Water Company*, 272 U.S. 400 (1926).

[143] *See* Sullivan Direct, p. 2.

[144] *See Energy Regulatory Comm'n v. Kentucky Power Co.*, 605 S.W.2d 46, 49 (Ky. App. 1980) *citing Lee v. International Harvester Co.*, 373 S.W.2d 418 (Ky. 1963).

[145] *See* Robert H. "Beau" Pratt Direct Testimony (Pratt Direct), p. 4 (filed Sep. 1, 2017); Lawler Direct, p. 3.

[146] *See* Pratt Direct, p. 3; Wathen Direct, p. 5.

[147] *See Public Service Comm'n of Ky. v. Continental Tel. Co. of Kentucky*, 692 S.W.2d 794, 799 (Ky. 1985) ("Generally accepted rate-making principles permit matters within the test year to be both normalized and annualized. There is also a provision for an adjustment because of known and measurable changes outside the test year").

[148] *See* Benjamin Walter Bohdan Passty Direct Testimony (Passty Direct), pp. 3-18 (filed Sep. 1, 2017).

year. The load forecast relied upon for the forecasted test year assumed a cumulative energy reduction associated with the Company's energy efficiency programs of 22,117 MWHs.[149] The Company's load forecast was not challenged by any intervenor. The development of the financial forecast was prepared under the supervision of Company witness Robert "Beau" Pratt and is fully described in his direct testimony.[150]

In developing the base period and forecasted test year, the Company made several assumptions that would fairly be characterized as conservative in nature. For instance, the Company did not include any specific inflation/price escalation or unit cost escalation in the calculation of the non-labor, non-fuel O&M expenses for either the estimated portion of the base period or the forecast period.[151] The Company plans to offset labor inflation through cost savings in order to achieve an overall flat O&M.[152] Likewise, Duke Energy Kentucky did not utilize a slippage factor for capital additions in either the base or forecasted period,[153] nor is it proposing to recover Construction Work in Progress (CWIP) in base rates.[154] Duke Energy Kentucky included the actual and anticipated revenues from its receipt of waste from other utilities in both its base and forecasted periods.[155] In conformity with Commission regulations,[156] the forecast contains the same assumptions and methodologies as used in the forecast prepared for use by the Company's

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[149] *See* Company Response to Staff DR-01-063.

[150] *See* Pratt Direct, pp. 5-13; *See also* Company Response to Staff-DR-01-009, 038 and 065.

[151] *See* Company Response to Kroger DR-01-004a.

[152] *See id.*

[153] *See* Company Response to Staff DR-01-013c.

[154] *See* Company Response to Staff DR-01-017.

[155] *See* Company Response to Staff DR-02-036.

[156] *See* 807 KAR 5:001, Section 16(7)(e)(2).

management.[157] With the exceptions noted below, the Company's forecast has not been challenged.

2. Capitalization

a. The Company's Proposed Capitalization is Reasonable

The Company has presented information in its Application to support a total capitalization allocated to electric operations for the forecasted period of $705,051,140.[158] The Company's jurisdictional electric rate base for the forecast period is $700,204,561.[159] Based upon adjustment made during the course of the case, the figure has changed slightly to a new total capitalization allocated to electric operations of $693,022,202. Each of the adjustments considered in arriving at this new figure are discussed in detail below.

i. Post-Filing Adjustments Due to the Tax Act

The changes to federal tax law occasioned by the Tax Act are generally discussed below in the context of the proposed adjustments to the Company's revenue requirement. However, the Tax Act also impacts the Company's capitalization. For instance, the Tax Act eliminates bonus depreciation, which allows utilities to provide a significant offset to the capital needs for projects because of the ability to expense, for tax purposes, a very large proportion of investments.[160]

To illustrate the impact of this change, with bonus depreciation, a utility may get to deduct, for tax purposes, about fifty percent of the cost of a project in the first year it is in service even for a project that may have a useful life of many years.[161] To demonstrate the significance of bonus deprecation, for a $1 million project, expensing fifty-percent of that cost in the first year for tax

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[157] *See* Lawler Direct, p. 3.

[158] *See* Application, Schedule A; Lawler Direct, p. 5.

[159] *See* Application, Schedule B-1; Lawler Direct, p. 6.

[160] *See* Don Wathen, Jr. Rebuttal Testimony (Wathen Rebuttal), p. 23 (filed Feb. 14, 2018).

[161] *See id.*

purposes but only five percent for book purposes, provides a significant offset to the capital needed to finance that project. In this example, $500,000 of the project cost would be deducted for tax purposes and $50,000 would be deducted for book purposes. The difference of $450,000 multiplied by the prevailing tax rate represents cash returned to the Company that offsets the investment.[162] At the new federal income tax (FIT) rate, the value of bonus depreciation would have been $94,500 ($450,000 * 0.21). Therefore, as a result of losing the bonus depreciation, the rate base and, therefore, the associated capitalization, of the utility increases and the customers' cost will increase as the return requirement is higher with higher capitalization.[163]

Likewise, the Company's capitalization will increase due to the impact of the change in the FIT on the calculation of deferred taxes.[164] Deferred taxes are calculated as the difference in an expense recorded for tax purposes multiplied by the tax rate.[165] Over the life of any asset, the Company's rate base will be higher simply because of the change in the FIT and, assuming that a dollar of capitalization is required to fund a dollar of rate base, the overall capitalization of the Company will be affected as well.[166]

Due to the recalculation of the accumulated deferred income tax (ADIT) balances to reflect the elimination of bonus depreciation and the projection of deferred income taxes at a lower FIT, the rate base and resulting rate base ratio calculation, the Company's necessary revenue requirement increases by $209,019.[167] In discussing the effect of the Tax Act, Kroger witness Mr.

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[162] *See id.*

[163] *See id.*

[164] *See id.*

[165] *See id.*

[166] *See* De May Rebuttal, p. 7; Wathen Rebuttal, p. 24. As Mr. Wathen stated under cross examination, the Company has not changed its capitalization for the increase resulting from the increase in the ADIT in this case. Such an adjustment will occur in a future rate case. *See* HVR 4:42:45 (Mar. 7, 2018).

[167] *See* Lawler Rebuttal, p. 4.

Bieber agreed that the elimination of bonus depreciation would likely have an impact upon the Company;[168] however, Mr. Kollen, on behalf of the AG, overlooked the negative impact of the legislation's elimination of bonus depreciation.[169] At the hearing, Mr. Kollen did not dispute the Company's calculation of the capitalization adjustment.[170]

ii. Post-Filing Adjustments for the East Bend O&M Regulatory Asset

Mr. Kollen alleges that Duke Energy Kentucky is somehow recovering two returns on the East Bend O&M regulatory asset.[171] He therefore proposes an adjustment to the Company's capitalization to remove the effect of the regulatory asset earning a return at the Company's weighted average cost of capital (WACC).[172] The Company agrees that it should not earn two returns on the same asset and positively asserts that Mr. Kollen's suggestion that it is doing so in this context is not accurate. Mr. Kollen's own proposal to reduce the amount of the regulatory asset acknowledges that the Company is only earning a return at the long-term debt rate, not the higher WACC.[173] Adjusting the Company's capitalization based upon an asset earning at a mis-stated rate of return significantly and improperly reduces the Company's revenue requirement.[174]

The appropriate way to resolve the issue raised by Mr. Kollen is to acknowledge that the East Bend O&M Regulatory Asset does not require an adjustment to capitalization. Instead, the Company's revenue requirement should be credited with the return actually expected to be earned

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[168] *See* Justin Bieber Direct Testimony (Bieber Direct), pp. 3-4 (filed Dec. 29, 2017).

[169] *See* HVR 4:45:35 (Mar. 8, 2018).

[170] *See id.*, 4:45:45.

[171] *See* Lane Kollen Direct Testimony (Kollen Direct), p. 53 (filed Dec. 28, 2017). Mr. Kollen's other recommendation to reduce the Company's revenue requirement further as an adjustment to the amortization of the regulatory asset it addressed in Section III.F.1., *infra*.

[172] *See* Kollen Direct, p. 53.

[173] *See* Wathen Rebuttal, p. 19.

[174] *See id.*

on the regulatory asset. Based upon the corrections to Mr. Kollen's worksheet supporting his proposal,[175] the overall revenue requirement would be credited with the actual return at the long-term debt rate. As set forth in the rebuttal testimonies of Mr. William Don Wathen Jr., and Ms. Sarah E. Lawler, this would equate to a reduction in the Company's revenue requirement of $1,554,681,[176] but no change required in the Company's proposed capitalization.

iii. Coal Ash Asset Retirement Obligation (ARO)

The Company originally included its coal ash ARO in its capitalization. Mr. Kollen recommended that it should be removed.[177] The Company agreed with this recommendation as part of its rebuttal testimony and included this adjustment as part of its revised revenue requirement calculation. The impact of this adjustment was a reduction to the Company's originally-filed revenue requirement by $1,629,904.[178]

b. The Attorney General's Proposed Adjustments to Capitalization are Unreasonable

The AG, through the testimony of Mr. Kollen makes almost $58 million in downward adjustments to the Company's electric capitalization. While the Company disagrees with most of Mr. Kollen's proposals, as detailed below, a more fundamental problem with the AG's suggestions is readily apparent: traditional ratemaking principles require a reconciliation of a utility's capitalization to its rate base. Indeed, 807 KAR 5:001, Section 16(6)(f) requires this as part of the Company's filing, and a measure of good ratemaking is the nexus between the two indices.[179]

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[175] *See* Wathen Rebuttal, Attachment WDW-Rebuttal-3.

[176] *See* Wathen Rebuttal, p. 20 (Corrected on Mar. 5. 2018); Lawler Rebuttal, p. 5 (Corrected on Mar. 5, 2018). Alternatively, the Commission could accept Mr. Kollen's adjustment to capitalization, but allow the Company to earn a return on the unamortized balance of the East Bend O&M regulatory asset at the WACC rather than the long-term debt rate.

[177] *See* Kollen Direct, pp. 55-56.

[178] *See* Lawler Rebuttal, p. 3 (Corrected on Mar. 5. 2018); Company Response to AG DR-02-004(e).

[179] *See* Application, FR 16(6)(f). which shows a total capitalization of $705.1 million and an electric rate base of $700.2 million.

However, Mr. Kollen has made no effort to reconcile his proposed capitalization adjustments to the Company's rate base, which results in him significantly understating the Company's electric utility investment valuation.[180] The inability of Mr. Kollen to cross-check his proposed adjustments against rate base – which has not been disputed by any intervenor – is itself good evidence that his proposals are more in the nature of gimmicks rather than credible suggestions.[181] While the Company has proposed to adjust its rates based upon capitalization, the assumption underlying the request was that any difference between capitalization and rate base would be immaterial. To the extent that the AG's proposals are entitled to any weight, greater consideration should be given to adjusting the Company's rates based upon its unchallenged rate base valuation in accordance with KRS 278.290.

i. Short-Term Affiliate Loans through the Money Pool Agreement

The Utility Money Pool Agreement authorizes Duke Energy, its regulated utility subsidiaries, and other named parties under the agreement, to participate in a money pool arrangement to better manage cash and working capital requirements.[182] When Duke Energy Kentucky has cash balances, it generally lends these funds into the Duke Energy Utility Money Pool.[183] Only in certain circumstances when the utility money pool is in a large cash surplus position does Duke Energy Kentucky invest in alternative short-term investments, such as government or Treasury money funds.[184] This surplus situation occurred for one day in November 2017, as detailed in the Company's response to data requests.[185] At the end of November 2017,

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[180] *See* Wathen Rebuttal, p. 32.

[181] *See* KRS 278.290 (setting forth standards for the valuation of utility property).

[182] *See* De May Rebuttal, p. 16.

[183] *See* Company Response to AG DR-02-009.

[184] *See id.*

[185] *See id.*

Duke Energy Kentucky was a lender into the money pool.[186] However, it is expected that Duke Energy Kentucky would transition from a lender to a borrower from the money pool in 2018.[187] When the Company issues long-term debt in the Fall of 2018, the Company will likely become a money pool lender again.[188]

Mr. Kollen, on behalf of the AG, recommends that short-term investments made by Duke Energy Kentucky in the Money Pool be excluded from the Company's capitalization.[189] His rationale is that if the Company earned a return on its rate base instead of its capitalization, these short-term investments would not be included.[190] To support his position, Mr. Kollen points out that Duke Energy Kentucky has an average investment (loan) position of approximately $5.1 million in the money pool during the 13-month forecast period.[191] He then suggests the Company should reduce its capitalization by the $5.1 million on the premise that if revenue requirements were calculated using rate base, this investment would be excluded from rate base.[192] Mr. Kollen also recommends that the $5.1 million reduction to capitalization be made on a pro rata basis across the entire capital structure, apportioning 10.4% to Short Term Debt, 40.7% to Long Term Debt and 48.9% to Equity.[193] The impact of his adjustment is a reduction to the Company's revenue requirement of $451,000.[194]

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[186] *See id.*

[187] *See id.*

[188] *See id.*

[189] *See* Kollen Direct, p. 51.

[190] *See id.*

[191] *See id.*, p. 52.

[192] *See id.*

[193] *See* Kollen Workpapers.

[194] *See* Kollen Direct, p. 52.

In reality, the Company is an investor (lender) into the money pool for roughly the first half of the forecast period and is a borrower from the money pool during the second half of the forecast period.[195] This reflects the fact that the Company manages its cash position to minimize unutilized cash.[196] Investing in short-term investments is not a corporate finance strategy, and certainly not one that Duke Energy Corporation employs.[197] Cash on hand is almost always used to pay down short-term indebtedness when it exists.[198] Thus, any reduction to its capitalization due to Money Pool investments should be solely attributed to the short-term debt portion of the capital structure and not attributed ratably across the entire capital structure. Off-setting either long-term debt or equity for the effects of short-term capitalization variations is punitive and does not reflect the true capitalization of the Company, *i.e.*, short-term debt (net of cash), long-term debt, and equity.[199] If the Commission accepts Mr. Kollen's adjustment to capitalization, it should only apply the short-term debt component of capitalization, which lowers Mr. Kollen's proposed reduction to $153,202.[200]

ii. The Balance of Deferred Demand Side Management (DSM) Costs

Mr. Kollen also asserts that the Company erred by not removing the DSM regulatory asset on its books from the jurisdictional electric capitalization used to calculate the revenue requirement in this proceeding.[201] However, the Company affirmed that the only amounts reflected in Account 0182401 are the (over)/under collected balance of the DSM Charge that the Company collects

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[195] *See* De May Rebuttal, p. 17.

[196] *See id.*, pp. 17-18.

[197] *See id.*, p. 18.

[198] *See id.*

[199] *See id.*, p. 18.

[200] *See* De May Rebuttal Attachment SGD-Rebuttal-1.

[201] *See* Kollen Direct, p. 54.

from its customers via Rider DSM.[202] No DSM costs are recovered through the Company's base rates and all DSM-related revenues and expenses were eliminated from the test period.[203] Although the revenue and expenses have been removed from the test period, the deferred balance - whether it is an asset or liability - should not be removed from capitalization.[204] The deferral balance is exclusively related to a cash flow issue *(i.e.,* over-and under-collection) that must be financed by shareholders.[205] The Company made no adjustment to capitalization for the DSM account, and accepting Mr. Kollen's recommendation would amount to punishing Duke Energy Kentucky's shareholders for financing the DSM program.[206] The AG's proposed adjustment should be rejected.

3. Operating Income Adjustments

a. Tax Cuts and Jobs Act Adjustments

Approximately three months after the filing of the Application in this case, Congress passed the Tax Act and thereby significantly reformed the federal tax code. The Tax Act has several impacts for the Company and its customers. The single greatest impact is the 40% reduction in the FIT rate,[207] which will significantly lower the Company's revenue requirement as grossed-up for taxes. The reduction in the FIT rate has significant implications for the Company's excess ADIT balance.[208] Likewise, utilities were granted an exemption from the Tax Act's general elimination of the net interest expense deduction. This exemption retains a valuable tax incentive

[202] *See* Company Response to AG DR-02-004a.

[203] *See id.*

[204] *See* Lawler Rebuttal, p. 7.

[205] *See id.* Thus, it presents the inverse of the situation Mr. Kollen cites with regard to the Money Pool. If the Company is required to reduce its capitalization to reflect a short-term Money Pool investment, it must also increase its capitalization to reflect that shareholders re financing the DSM regulatory asset.

[206] *See* Company Response to AG DR-02-004b.

[207] *See* De May Rebuttal, p. 7.

[208] *See id.*, p. 9. An ADIT measures the value of taxes collected from a customer, but not yet paid to a taxing authority.

that will flow through to the Company's customers.[209] While the Tax Act eliminated bonus depreciation accounting procedures, it retained the modified accelerated cost recovery system (MACRS) for calculating depreciation expense on capital investments for computing current income tax expense.[210] The result of this is that regulated utilities will continue to accrue deferred income taxes, but will do so at a slower rate than under the prior bonus depreciation rules and higher FIT.[211] In addition, the Tax Act eliminated the manufacturing deduction,[212] which will also be detrimental to customer rates.[213]

Thus, when considered as a whole, the lower FIT rate has the effect of reducing the amount of federal income tax expense that the Company must collect through rates.[214] The revenue requirement would also be lowered through the amortization of excess ADITs.[215] At the same time, the lower tax rate, the elimination of bonus depreciation and the amortization of excess ADIT balances will increase the Company's rate base and consequently, its capitalization more rapidly, driving a higher revenue requirement.[216]

i. FIT Rate Adjustment

The single greatest impact of the Tax Act is the reduction in the FIT rate from 35% to 21%.[217] The Company has proposed to adjust its revenue requirement to account for the tax rate

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[209] *See id.*, pp. 7-8.
[210] *See* De May Rebuttal, p. 8.
[211] *See id.*
[212] *See id.*
[213] *See id.*, p. 9.
[214] *See id.*, pp. 11-12.
[215] *See id.*, p. 12.
[216] *See id.*
[217] *See id.*, p. 7.

reduction by making a $10,622,916 reduction,[218] which is slightly larger than Mr. Kollen's proposed adjustment of $10.255 million.[219] The Company's calculation should be approved.

ii. January – March 2018 FIT Adjustment

To account for the period of time from January 1, 2018 through the date that new rates are put into effect herein, the Company is offering a proposal similar to that agreed to by the AG and KIUC in Case No. 2018-00034.[220] The proposal is presented in Attachment WDW-Rebuttal-4 to the Rebuttal Testimony of Mr. Wathen and is more fully described therein.[221] In essence, the Company proposes to reduce the revenue requirement by $110,762,[222] which should be approved.

iii. Excess ADITs

As of December 31, 2017, Duke Energy Kentucky had a significant net deferred tax liability, booked at a 35% corporate FIT rate and driven overwhelmingly by accelerated depreciation of fixed assets for tax purposes.[223] Because a deferred tax liability represents taxes collected from customers but not yet paid to taxing authorities, and because the ultimate payment of these taxes will now occur at a 21% corporate FIT rate, the balance of deferred tax liability must be remeasured.[224] The resulting "excess" ADIT balance is also a regulatory liability.[225] The Tax Act requires that excess deferred income taxes generally associated with property, and specifically connected to the accelerated depreciation of property, must be normalized into customers rates in

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[218] *See* Lawler Rebuttal, p. 3.

[219] *See* Kollen Direct, p. 48.

[220] *See In the Matter of: Kentucky Industrial Utility Customers, Inc. v. Kentucky Utilities Company and Louisville Gas and Electric Company,* Order, Case No. 2018-00034 (Ky. P.S.C. Mar. 20, 2018).

[221] *See* Wathen Rebuttal, pp. 30-31.

[222] *See* Lawler Rebuttal, p. 4.

[223] *See* De May Rebuttal, p. 9.

[224] *See id.*

[225] *See id.*

a highly prescribed manner that mimics the remaining life of the underlying assets.[226] The method for refunding all other excess deferred taxes is a matter left to the Commission to decide in the ratemaking process.[227]

Mr. Kollen's testimony recommends a total reduction in revenue requirement related the refund of excess ADITs of $6.054 million;[228] however, he failed to make a distinction between protected ADITs and unprotected ADITs.[229] At the hearing, Mr. Kollen agreed that that protected excess ADITs should be returned in accordance with the Average Rate Assumption Method (ARAM) method specified in federal law.[230] He also failed to take into account the impact of state income taxes,[231] based his estimates on forecasted ADITs instead of the actual ADITs that existed on December 31, 2017,[232] and failed to properly compute the updated gross revenue conversion factor (GRCF).[233] Accordingly, Mr. Kollen's calculations should be disregarded.

A) Amortization of Protected Excess ADITs

The Tax Act is clear on the treatment of excess protected ADITs, and in Duke Energy Kentucky's case, those must be reversed over the life of those assets under the ARAM method of amortization.[234] The amortization for protected excess ADITs is dynamic and may change annually.[235] The ARAM method, as set forth in the Tax Act, reduces the excess tax reserve over

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226 *See id.*

227 *See id.*

228 *See* Kollen Direct, p. 48.

229 *See* Lisa Bellucci Rebuttal Testimony (Bellucci Rebuttal), pp. 3-4 (filed Feb. 14, 2018); AG Response to Company DR-01-070.

230 *See* HVR 3:02:35 (Mar. 8, 2018).

231 *See* Wathen Rebuttal, p. 27.

232 *See id.*, p. 28.

233 *See id.*

234 *See* De May Rebuttal, p. 14.

235 *See* Bellucci Rebuttal, p. 5.

the remaining regulatory lives of the property that gave rise to the reserve for deferred taxes during the years in which the deferred tax reserve related to such property is reversing.[236] The reversal of timing differences generally occurs when the amount of the tax depreciation is less than the amount of book depreciation for any given asset.[237] Therefore, the ARAM calculation is calculated on each individual asset and is dependent on the remaining book and tax bases for that asset.[238] The Company has calculated the estimated balances of these excess protected ADITs as being $34,912,797.[239] The Company has also prepared an amortization schedule for the protected ADIT balance that follows the ARAM normalization methodology.[240] As set forth in the rebuttal testimony of Company witness, Lisa Bellucci, the amortization of the updated protected ADITs is $1,168,705 for the forecasted test year.[241]

B) Amortization of Unprotected Excess ADITs

The Commission's Order in Case No. 2017-00477 required the Company to create a regulatory liability to reflect the amount of the excess ADITs to be returned to customers over a twenty year period.[242] As set forth in the rebuttal testimony of Ms. Bellucci, the annual amortization amount for the $33,032,786 in unprotected excess ADITs at twenty years is $1,651,639.[243] At the hearing, Mr. Kollen did not dispute the Company's calculations.[244]

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[236] *See id.*

[237] *See id.*

[238] *See id.*, pp. 5-6.

[239] *See* Bellucci Rebuttal, Attachment LMB-1, p. 1.

[240] *See* De May Rebuttal, p. 14. For purposes of reflecting the adjustment for the protected ADITS in the revenue requirement, the Company is calculating an adjustment that factors in the normalization of these balances for the 2018 as well as the first three months of 2019, to reflect the forecasted test year impact. *See* Bellucci Rebuttal, p. 5.

[241] *See id.*, Attachment LMB-1, p. 1.

[242] *See In the Matter of: Kentucky Industrial Utility Customers, Inc. vs. Kentucky Utilities Company, Louisville Gas and Electric Company, Kentucky Power Company, Duke Energy Kentucky, Inc.*, Order, Case No. 2017-00477 (Ky. P.S.C. Dec. 27, 2017).

[243] *See* Bellucci Rebuttal, Attachment LMB-1, p. 1.

[244] *See* HVR 4:46:05 (Mar. 8, 2018).

The primary point of contention is the period of time over which the unprotected excess ADIT balance should be amortized. Kroger does not recommend that the Commission adopt any particular amortization period.[245] The AG, however, abandoned his original twenty-year proposal and now requests a refund of all unprotected excess ADITs within five years.[246] The principle reason for this shorter amortization period in this instance is the apparent fact that the Company and the AG were not able to reach a settlement in this proceeding.[247] The AG's witness, Mr. Kollen, raised for the first time during qualification on direct examination that he was no longer supporting the twenty-year adjustment included in his pre-filed direct testimony, but rather was now supporting a five year amortization period.[248] It is very unreasonable for the AG to raise this issue for the first time at the hearing despite taking more reasonable positions in other cases. For instance, the AG recently agreed to a fifteen-year amortization in the case of KU and LG&E, which the Commission approved,[249] and Mr. Kollen's client agreed to a fifteen year amortization of unprotected excess ADITs in the context of the Company's natural gas operations.[250] The AG's position is confiscatory, plainly inconsistent with any notions of due process, and fails to achieve an equitable outcome. The Commission should not adopt a policy where utility customers receive different benefits from unprotected excess ADIT refunds based upon what utility serves them. The outcome requested by the AG is arbitrary, capricious and unreasonable.

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[245] *See* Kroger Response to Company DR-01-011, 012.

[246] *See* HVR 4:46:16 (Mar. 8, 2018).

[247] *See id.*, 3:34:25.

[248] *See id.* Mr. Kollen explained his new position by stating, "I think [a fifteen-year amortization] was reasonable within a settlement context for KU and LG&E. I don't think it's reasonable if the Commission has to decide the issue outright...There's no reason to do anything longer than five years."

[249] *See In the Matter of: Kentucky Industrial Utility Customers, Inc. v. Kentucky Utilities Company and Louisville Gas and Electric Company*, Order, Case No. 2018-00034, Appendix C (Ky. P.S.C. Mar. 20, 2018).

[250] *See In the Matter of: Kentucky Industrial Utility Customers, Inc. vs. Kentucky Utilities Company, Louisville Gas and Electric Company, Kentucky Power Company, Duke Energy Kentucky, Inc.*, Order, Case No. 2017-00477 (Ky. P.S.C. Dec. 27, 2017).

A five-year return of the unprotected excess ADITs would return the benefits of the Tax Act to consumers quickly, but it would also lead to several unreasonable and negative outcomes. The implementation of the Tax Act has the potential to adversely affect the Company's cash flow needed to fund ongoing operations and new infrastructure investments.[251] An unmitigated cash flow shortfall could force the Company to rely excessively on third-party capital to fund itself, to the ultimate detriment of its financial condition.[252] Mr. De May summarized the Company's concerns as follows:

> Duke Energy Kentucky has worked hard over the years to keep customers' rates well below the national average. The Company has accomplished this while providing safe, reliable and increasingly clean energy. These federal tax law changes provide the Commission an opportunity to help reduce and smooth out customer rates over the short- and longer-term, while maintaining the utility's ability to provide safe, reliable and affordable rates. Keeping with this strong tradition, and as further described by Mr. Wathen, Duke Energy Kentucky proposes appropriate adjustments to reflect the impact of the Tax Act.
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> The Company urges the Commission to look beyond just the reductions in tax expense afforded under the Tax Act and to focus on the bigger picture of the Tax Act as it relates to the reasonableness of the utility's rates now and going forward. This approach is beneficial for both customers and the utilities and necessarily includes consideration of both the immediate and longer term impacts of the Tax Act, the current financial condition of the utility, and an appreciation of what the impact of a sudden reduction in utility rates will have.[253]

While the Company agrees that customers should receive the appropriate level of excess deferred taxes, it must be done over a reasonable period so as not to unfairly harm the Company. An appropriate balance must be struck between reversing these excess balances and returning them

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[251] *See* De May Rebuttal, p. 14.

[252] *See id.*, p. 14; Company Response to Staff Post-Hearing DR-01-006 (filed Mar. 23, 2018).

[253] *See* De May Rebuttal, p. 15.

to customers and maintaining the Company's credit quality. Since the majority of the unprotected excess deferred taxes relate to property, plant and equipment, it is reasonable to refund those amounts over the period over which the deferred tax balances would have otherwise reversed, and consistent with the remaining book life of the underlying assets.

A more rapid refund of the unprotected excess ADIT has an adverse impact on the Company's cash flows, which are needed to fund ongoing operations and new infrastructure investments. This financial risk has been noted by credit rating agencies in recent months actually placing Duke Energy Corp. on a negative outlook as a result of the potential regulatory treatment of the Tax Act.[254] Duke Energy Kentucky's own credit rating is under careful examination by these same rating agencies that have identified the challenges the Company is facing in relation to increased capital expenditures and factors that could lead to a downgrade for Duke Energy Kentucky as follows:

- Cash flow from operations excluding working capital changes to debt falling below the high teens;
- Higher capital expenditures resulting in a material increase in debt levels; and
- A decline in the credit supportiveness of the regulatory environment in Kentucky.[255]

A five-year amortization of the unprotected excess ADITs is unreasonable as it would exacerbate the cash flow issue for the Company and result in less funds to invest in its day-to-day operations. Moreover, as the balance of the excess ADIT liability declines, the Company's rate base and, consequently, its capitalization, will increase. The potential impact from a credit

[254] *See* Company's Response to Staff-Post-Hearing-Data Request-01-006. Attachment 2

[255] *Id.* at Attachment 3.

downgrade due to increased borrowings as a result of an unreasonable cash flow constraint would ultimately harm customers. When the Company files its next electric base rate case, the effect of this unreasonably accelerated refund of unprotected excess ADITs will be more dramatic. And, of course, an arbitrary policy that leads to discriminatory treatment of various utilities operating under the same general principles of federal tax law is itself unlawful and unreasonable. For each and all of these reasons, the AG's proposed five-year amortization of unprotected ADITs should be denied.

b. Depreciation Adjustments

i. The Company's Decommissioning Study Should be Accepted

As part of the Application, the Company provided the testimony of Mr. Jeffrey T. Kopp and a decommissioning study he prepared for each of the generating stations currently owned by Duke Energy Kentucky. The decommissioning study was prepared to most accurately represent what contractors would likely bid to dismantle the equipment, address environmental issues, and restore each site through a competitive bidding process, based on performing known dismantlement tasks under ideal conditions.[256] In addition to these known tasks under ideal conditions, indirect costs were added to cover costs incurred by the Company in executing the projects, and contingency expense was added to account for unknown, but reasonably costs.[257] Because the decommissioning study uses current dollars, and plant decommissioning will take place at some point in the future, it is necessary to use a price escalator to account for the timing difference.[258]

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[256] *See* Jeffrey T. Kopp Direct Testimony (Kopp Direct), p. 4 (filed Sept. 1, 2017).

[257] *See id.*, p. 5.

[258] *See* Company Response to AG DR-01-037.

Mr. Kollen did not offer an alternative decommissioning study,[259] nor did he dispute that the cost of decommissioning is traditionally considered a cost of providing utility service and ordinarily recoverable from customers.[260] Nevertheless, he recommended that the Commission eliminate escalation from the decommissioning costs included in the Company's rates.[261] Such a proposal would prevent the Company from fully recovering the cost of the assets that are currently benefitting customers,[262] and would amount to a confiscation of property. Based upon the foregoing, the Company's decommissioning study should be accepted.

ii. The Company's Depreciation Study Should be Approved

As part of the Application Duke Energy Kentucky tendered a depreciation study prepared by Mr. John J. Spanos of Gannett Fleming Valuation and Rate Consultants, LLC.[263] The purpose of the depreciation study is to estimate the annual depreciation accruals related to electric and common plant in service for ratemaking purposes and determine appropriate average service lives and net salvage percentages for each plant account.[264] Mr. Kollen, on behalf of the AG, raises several objections to the Company's proposed depreciation methodology, but there is no

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[259] *See* HVR 4:23:30 (Mar. 8, 2018).

[260] *See In the Matter of the Electronic Application of Kentucky Power Company For (1) a General Adjustment of its Rates for Electric Service; (2) an Order Approving its 2017 Environmental Compliance Plan; (3) an Order Approving its Tariffs and Riders; (4) an Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities; and (5) an Order Granting all Other Required Approvals and Relief*, Order, Case No. 2017-00179 (Ky. P.S.C. Jan. 18, 2018). The Company's position regarding the recoverability of the costs of the decommissioning study were stated in Company Response to Staff DR-03-002a. Neither Mr. Kollen nor any other intervenors' witness objected to this in the submission of direct testimony.

[261] *See* Kollen Direct, pp. 41-42.

[262] *See* John J. Spanos Rebuttal Testimony (Spanos Rebuttal), p. 26 (filed Feb. 14, 2018).

[263] The depreciation study was mandated by a prior Commission Order in Case No. 2015-00120. *See In the matter of: Application of Duke Energy Kentucky, Inc. for an Order Approving the Establishment of a Regulatory Asset for the Depreciation Expense of its East Bend Unit 2 Generating Station*, Order, Case No. 2015-00120 (Ky. P.S.C. Aug. 20, 2015). The depreciation study was filed as Attachment JJS-1 to the Direct Testimony of Mr. Spanos.

[264] *See* John J. Spanos Direct Testimony (Spanos Direct), p. 3 (filed Sep. 1, 2017).

depreciation study offered by the AG as an alternative.[265] Accordingly, the Company requests the Commission to approve the new depreciation and amortization rates and that they be made effective on the same date that the Company's new base electric rates become effective.[266]

iii. The Equal Life Group (ELG) Methodology is More Appropriate than the Average Life Group (ALG) Method for Determining Depreciation

Under the ELG procedure, a group of property *(e.g.,* a vintage within a property account) is subdivided into groups having equal service lives.[267] The size of these equal life groups is based on the estimated survivor characteristics of the account.[268] Depreciation can then be calculated for each equal life group based on the straight line method; that is, an equal amount of the group's service value is recorded as depreciation expense in each year of service.[269] The total depreciation for an account is the summation of the depreciation calculated for each equal life group.[270] In other words, based on the survivor curve estimate for an account, the ELG procedure mathematically estimates the life for each unit in the account, and then depreciates each unit over its expected life.[271] For this reason, the procedure is also known as the "unit summation" procedure.[272] The Company's current depreciation rates are calculated based upon the ELG procedure.[273]

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[265] *See* HVR 4:20:10 (Mar. 8, 2018).

[266] *See* Cynthia S. Lee Direct Testimony (Lee Direct), p. 7 (filed Sep. 1, 2017); *see also Public Service Comm'n of Kentucky v. Dewitt Water District*, 720 S.W.2d 725, 730 (Ky. 1986) ("Depreciation is uniformly recognized as an operating expense and it is important that the amounts set aside to cover depreciation of public utility property be large enough to replace the property when it is worn out.") *citing* 64 Am.Jur.2d *Public Utilities* § 182 (1972).

[267] *See* Spanos Rebuttal, p. 29.

[268] *See id.*

[269] *See id.*

[270] *See id.*

[271] *See id.*, pp. 29-30.

[272] *See id.*, p. 30.

[273] *See id.*

By calculating depreciation for each equal life group, the ELG procedure contrasts with the ALG procedure, which depreciates every asset within an account over the average life of the account.[274] As demonstrated in Company witness Spanos' testimony, the ALG procedure does a poor job of matching cost recovery to the actual consumption of the service life of an asset.[275] Moreover, the ELG procedure incorporates the reality of "dispersion," which recognizes that in actual utility operations only a very small percentage of the dollars of plant investment in an account will actually be retired at the average service life determined for an account.[276] Because the ELG procedure recognizes dispersion, it allocates costs for each equal life group over the expected life for that group.[277] As a result, the ELG procedure allocates cost in a manner that approximates the result of each asset being depreciated over its actual life. The ALG procedure fails to do this.[278] And finally, it must be noted that Dr. Robley Winfrey, the noted Iowa State University professor who developed the Iowa survivor curves that are universally used to estimate service lives based on historical data – and who is generally regarded as the father of utility depreciation rates – referred to the ELG procedure as "the only mathematically correct procedure."[279]

Mr. Kollen did not undertake any separate analysis to support his recommendation to use the ALG depreciation method in place of the ELG procedure.[280] Instead, it appears he simply chose the ALG method because it produces a lower depreciation expense, $6.939 million lower,

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[274] *See id.*

[275] *See id.*, pp. 30-34

[276] *See id.*, p. 34.

[277] *See id.*, p. 36.

[278] *See id.*

[279] *See id. citing* Winfrey, Robley, "Depreciation of Group Properties", Bulletin 155 (Ames, IA: Iowa State University Press, 1942, reprinted 1969) p. 71.

[280] *See* AG Response to Company DR-01-082; HVR 4:20:40 (Mar. 8, 2018).

in the short-term.[281] While this would benefit the Company's current customers, it would be highly prejudicial to the Company's future customers,[282] and is inconsistent with the authorities and evidence cited above. In particular, if Duke Energy Kentucky was required to shift to the ALG method for calculating its depreciation expense, its rate base and capitalization would stay higher longer because its assets would not be depreciating at their current rates, and would actually begin depreciating at a much slower rate, resulting in customers also paying significantly more through a return on that higher base in the future.[283] Mr. Kollen could cite no authority requiring the use of ALG depreciation.[284] His recommendation is unsustainable and should be ignored.

iv. Terminal Net Salvage Should be Included in Depreciation Rates

The AG's other depreciation-related adjustment relates to the inclusion of terminal net salvage in the Company's depreciation rates. Net salvage, as used in depreciation, is defined as gross salvage less cost of removal.[285] When an asset is retired it may have scrap or reuse value, which is gross salvage.[286] Most types of utility property typically experience negative net salvage, meaning that cost of removal exceeds gross salvage.[287] Net salvage is part of the service value, or overall cost, of an asset.[288] In order to equitably allocate the full cost of an asset over its service life, net salvage must be estimated while the asset is still in service and allocated over the life of

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281 *See* Kollen Direct, pp. 35-36.

282 *See* Spanos Rebuttal, pp. 3-4.

283 *See id.*, p. 24.

284 *See* HVR 4:20:30 (Mar. 8, 2018).

285 *See* Spanos Rebuttal, p. 3. A net salvage value may be either positive or negative depending upon whether the salvage value is greater or less than the salvage value. *See id.*, pp. 8-9.

286 *See id.*, p. 3.

287 *See id.*

288 *See id.*

the asset.[289] In this case, the Company has prepared its depreciation study using the "traditional method" that is accepted by the vast majority of jurisdictions (including Kentucky) and FERC.[290]

In his testimony, Mr. Kollen indicates that there are three approaches for allowing recovery of net salvage expense: (1) recovery through depreciation over the life of an asset; (2) no net salvage is included in depreciation; and (3) net salvage is amortized over a period of time after the asset is retired.[291] Mr. Kollen generally favors the third approach, but, in so doing, he fails to mention that only the first of these approaches is consistent with the FERC Uniform System of Accounts (USoA), is widely accepted, and results in intergenerational equity.[292] The second and third approaches recover net salvage after an asset has been retired, which is not consistent with the USoA or widely accepted depreciation practices.[293]

Again, Mr. Kollen's recommendation is based upon expediency and lacks any independent analysis.[294] Under his theory, the Commission should assume that Duke Energy Kentucky will not dismantle any retired power plants, but will simply retire them in place.[295] Thus, Mr. Kollen reasons, no terminal net salvage expenses should be included in the depreciation calculation.

Mr. Kollen's suggestion is an invitation to adopt bad policy and violates the USoA. General Instruction 22 of the USoA requires utilities to "use a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property over the service life of the property."[296] Service value is further defined as "the difference between original cost and

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289 *See id.*

290 *See id.*, p. 10.

291 *See* Kollen Direct, pp. 36-38.

292 *See* Spanos Rebuttal, p. 4.

293 *See id.*

294 *See* HVR 4:29:16 (Mar. 8, 2018).

295 *See* AG Response to Company DR-01-042

296 Spanos Rebuttal, p. 4 *citing* FERC USoA Instruction 22.

net salvage value of electric plant."[297] Thus, the USoA is clear that net salvage must be allocated over the service life of utility property. Mr. Kollen's proposal to defer net salvage is not consistent with the requirements of the USoA[298] or, for that matter, the NARUC Public Utility Depreciation Practices Manual (NARUC Manual) or *Depreciation Systems*, the authoritative text on the subject.[299]

Likewise, Mr. Kollen could cite no authority requiring the Commission to approve his recommendation.[300] And while he once again cited his "experience" and the Commission's historical practice as authority to support his position,[301] Mr. Kollen could not cite a single Kentucky case that actually affirmed his absolutist position.[302] To the contrary, it is abundantly clear that the Commission has expressly rejected the AG's recommendation in the past.[303]

Mr. Kollen's recommendation also fundamentally violates the matching principle of cost-causation, which holds that those customers who benefit from a utility asset should be the one who pay for the asset.[304] Including net salvage in depreciation results in intergenerational equity, as the net salvage costs are part of the cost of an asset and should be recovered over its service life.[305] As stated in the NARUC Manual:

> Historically, most regulatory commissions have required that both gross salvage and cost of removal be reflected in depreciation rates. The theory behind this requirement is that, since most physical plant placed in service will have some residual value at the time of retirement, the original cost recovered through depreciation should

[297] Spanos Rebuttal, p. 5 *citing* FERC USoA Definition 37

[298] *See* Spanos Rebuttal, p. 21.

[299] *See id.*

[300] *See* HVR 4:25:25 (Mar. 8, 2018).

[301] *See* Kollen Direct, pp. 39-40; AG Response to Company DR-01-044 and 045.

[302] *See* HVR 4:28:20 (Mar. 8, 2018).

[303] *See In the Matter of the Adjustment of the Gas Rates of The Union, Light, Heat and Power Company*, Order, Case No. 2005-0042, pp. 36-39 (Ky. P.S.C. Dec. 22, 2005).

[304] *See* Spanos Rebuttal, p. 23.

[305] *See id.*

be reduced by that amount. Closely associated with this reasoning is the accounting principle that revenues be matched with costs and the regulatory principle that utility customers who benefit from the consumption of plant pay for the cost of that plant, no more, no less. The application of the latter principle also requires that the estimated cost of removal of plant be recovered over its life.[306]

In *Depreciation Systems*, the same point is expressed as follows: "The matching principle specifies that all costs incurred to produce a service should be matched against the revenue produced. Estimated future costs of retiring an asset currently in service must be accrued and allocated as part of the current expenses."[307]

When Mr. Kollen raised the same argument in North Carolina, it was summarily rejected:

> The Commission concludes that Nucor Witness Kollen's recommendation to ignore interim cost of removal and net salvage is unsubstantiated and witness Stevens' testimony that witness Kollen's proposal would be contrary to Generally Accepted Accounting Principles and the FERC USoA has not been challenged. Accordingly, the Commission finds and concludes that this recommendation should not be adopted.[308]

The North Carolina Utilities Commission, and other jurisdictions that have rejected the concept advanced by Mr. Kollen are right.[309] Mr. Kollen's position is outside the mainstream of

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[306] NARUC Public Utility Depreciation Practices Manual, p. 157.

[307] Fitch, Frank K. and Wolf, Chester W. *Depreciation Systems*. John Wiley & Sons, Inc. (1994).

[308] *See* Company Hearing Exhibit 12, p. 44. As an aside, the North Carolina Utilities Commission did not accept any of Mr. Kollen's recommendations and easily discredited all of them.

[309] *See e.g. In the Matter of Central Illinois Light Company d/b/a Ameren CILCO, Central Illinois Public Service Company d/b/a Ameren CIPS, Illinois Power Company d/b/a Ameren IP, proposed General Increase in Rates for Delivery Service*, Order, Docket Nos. 07-0585, 07-0586, 07-0587, 07-0588, 07-0589 and 07-0590, pp. 138-139 (Ill. Com. Comm. Sep. 24, 2008); *In the Matter of Laclede Gas Company's Tariff to Revise Natural Gas Rate Schedule*, Third Report and Order, Case No. GR-99-315, p. 16 (Mo. P.S.C. Jan. 11, 2005); *In the Matter of the Application of Pacific Gas & Electric Co. (U39-M) or Authorization to, Among Other Things, Increase Rates and Charges for Electric and Gas Service, Effective January 1, 2007*, Order, D. 07-03-044 in A.05-12-002 (Cal. P.U.C. Mar. 15, 2007); *In the Matter of PSI Energy, Inc. for Authority to Increase its Rates & Charges for Electric Service; for Approval of New Schedule of Rates and Charges and Rules and Regulations Applicable to Such Rates and Charges; for the Authority to Reflect its Qualified Pollution Control Property and Other Relief*, Order 051804, Case NO. 42359, pp. 70-71 (I.R.U.C. May 18, 2004).

regulatory policy and inconsistent with both Generally Accepted Accounting Principles and FERC's USoA.[310]

Moreover, the suggestion that Duke Energy Kentucky will simply let a retired plant lay abandoned is inconsistent with the record of the case. Following the retirement of the Miami Fort 6 Unit, as a results of the MATS rule, Duke Energy Kentucky has taken active measures to secure and mitigate the potentially hazardous effects of a plant retirement pending its eventual demolition.[311] It is not economically feasible to dismantle Miami Fort 6 while the adjacent Miami Fort units, which are owned by a third-party, remain operational.[312] Nonetheless, the Company must engage in decommissioning work as outlined in its decommissioning study now, so as to keep the station in a safe state until final dismantlement can occur.

The ill-effects of Mr. Kollen's recommendations would be profound. Not only would the recommendation result in intergenerational inequity, it would also be more expensive to customers on a total cost of service basis over the long term.[313] Each of the depreciated-related adjustments suggested by the AG are unreasonable and contrary to law.[314] Accordingly, they should be summarily rejected.

c. Replacement Power

The AG proposes an adjustment to the Company's test year expense that is related to the cost of power purchased by Duke Energy Kentucky as replacement power for forced outages that

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310 *See* Spanos Rebuttal, pp. 27-28.

311 *See* Company Response to AG DR-01-027a-b.

312 *See* Kopp Direct, p. 5.

313 *See* Spanos Rebuttal, pp. 23.

314 *See Public Service Comm'n of Kentucky v. Dewitt Water District*, 720 S.W.2d 725, 730 (Ky. 1986) ("The rates established by the Commission will not generate sufficient revenues to enable the districts to provide for an adequate depreciation account and replacement fund. Disallowance of depreciation expense as a rate recovery permits a substantial portion of the property of the district to be consumed by present customers without requiring the customers to pay for replacement.").

are not recoverable through the fuel adjustment clause (Rider FAC). Mr. Kollen agrees that it was appropriate to establish a deferral account to track the incremental costs of replacement power purchases.[315] Philosophically, Mr. Kollen also agrees that the objective in this situation is to use the best estimate of replacement power costs when including such an expense in base rates because, over the long-term, this will tend to keep the deferral account closer to zero.[316] He disagreed with the dollar amount of replacement power expense that should be included in base rates, however, and relied only upon data from 2015, 2016 and the first ten months of 2017 to support his recommendation.[317] As a result of excluding relevant known and measurable actual data, Mr. Kollen recommends reducing the replacement power expense included in base rates to $1.610 million.[318]

The analytical flaw in Mr. Kollen's recommendation is his continued resolve to use only that data which supports his pre-determined opinion. Mr. Kollen's recommendation is based upon data that the Company provided and that clearly included replacement power costs for 2013 and 2014,[319] yet he willfully chose not to incorporate such data. Excluding historical data points that are subjectively deemed "too volatile" produces an average that is not truly accurate, and it unreasonably shifts all risk of future volatility to the Company. Moreover, it contradicts Mr. Kollen's own standard for forecasting future expenses because, as he explained in responses to information requests, "the best evidence of a reasonable forecast expense in the test year is recent

[315] *See* Kollen Direct, p. 12; *see also* Section III.F.2., *infra*.

[316] *See* HVR 3:41:10 (Mar. 8, 2016); Wathen Rebuttal, p. 8.

[317] *See* Kollen Direct, p. 12. At the hearing, Mr. Kollen demonstrated unusual sensitivity to the reasonableness of his calculations by defending them when they were not even the subject of the line of questioning. *See* HVR 3:14:22 (Mar. 8, 2018).

[318] *See* Kollen Direct, p. 12; HVR 3:41:40 (Mar. 8, 2018).

[319] *See* Kollen Direct, Exhibit LK-4. Mr. Kollen's Polar Vortex argument still does not account for why he would disregard data from 2013 or the months in 2014 that were not impacted by the Polar Vortex.

actual experience...."[320] Mr. Kollen's apparent rationale that it is better to use less actual data for volatile expenses and more actual data for non-volatile expenses (as he did with regard to vegetation management expenses) is irrational and contrary to reason and accepted practice.[321] It is remarkable that while Mr. Kollen accepts the product of the Company's modeling in advocating for projected wholesale margins to support his profit sharing recommendations, he criticizes the exact same model that supports the replacement power figure here.

Moreover, the specific reasoning behind Mr. Kollen's exclusion of relevant historical data is equally unpersuasive.[322] PJM certainly does not share Mr. Kollen's concern that extreme winter weather will never again grip the Midwest in the near future. As the Commission is fully aware, PJM has instituted the Capacity Performance Market specifically to guard against the ill-effects of prolonged peaks.[323] If PJM shared Mr. Kollen's concern that the Polar Vortex of 2014 was purely aberrational, there would have been little need to so dramatically reshape the capacity market. Mr. Kollen, who lacks any training as a meteorologist or climatologist has no firsthand knowledge as to whether it is reasonable to exclude data from 2013 and 2014 based upon weather forecasts.[324]

It is also undisputed that Duke Energy Kentucky is now subject to more generation concentration risk as a result of its MATS-induced retirement of Miami Fort 6 and the corresponding acquisition of the DP&L interest in East Bend.[325] An outage at East Bend will likely have a more significant impact upon the Company than in years past when Miami Fort 6

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[320] *See* AG Response to Company DR-01-053.

[321] *See* Wathen Rebuttal, p. 4.

[322] Though he relied upon the Polar Vortex as the reason for excluding data for 2013 and 2014, the Polar Vortex did not last for twenty-four months. Thus, even under his own rationale, many additional months of data that were available should have been used.

[323] *See* Verderame Direct, p. 20.

[324] *See* HVR 3:45:59 (Mar. 8, 2018).

[325] *See* Wathen Rebuttal, p. 15.

provided a physical hedge against forced outages at East Bend.[326] Thus, the risk of volatility in the Company's power purchase expense has increased, not decreased, as Mr. Kollen implies.[327]

There is no logical reason to purposefully exclude 2013 and 2014 from the calculation of the Company's historic replacement power expense. And, even if the estimate of replacement power expense included in base rates turns out to be too optimistic, which is unlikely, the agreed upon deferral account will provide an adequate backstop to assure that customers are not over-charged. The Company's calculation is based on a probabilistic model using reasonable modeling assumptions and the estimated $5.7 million in annual replacement power expense,[328] as compared to the AG's admittedly limited historical average for this expense, is reasonable. There is no good reason to force a future generation of customers to pay for the replacement power expense incurred by the current generation of customers. Accordingly, the AG's recommended adjustment should be rejected.

d. Planned Outage O&M Normalization

Planned outage costs are highly volatile for Duke Energy Kentucky. The Company's Application demonstrated that the range of planned outage expense from 2013 through 2019 is $0 on the low end and over $14 million at the high end.[329] Duke Energy Kentucky follows a regular maintenance schedule for all its plants. Generally speaking, the stations have annual maintenance activities scheduled during off-peak seasons in the spring or fall.[330] The regular maintenance is

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[326] *See* Verderame Direct, p. 16; Wathen Rebuttal, p. 7.

[327] *See* Wathen Rebuttal, p. 7; *see also* Company's Response to Staff Post-Hearing DR-01-012.

[328] *See* Wathen Rebuttal, pp. 4-5. If Mr. Kollen's methodology was adopted with the modification that all available data was taken into account and the replacement power costs for East Bend were grossed-up to reflect full ownership, the average annual cost of replacement power would be $4,107,332. *See* Wathen Rebuttal, Attachment WDW-Rebuttal-1.

[329] *See* Application, Schedule C-2; Wathen Rebuttal, p. 14.

[330] *See* Miller Direct, p. 8.

typically one to two weeks of planned outage in duration.[331] Every other year, a longer-term outage is scheduled for more significant projects.[332] In the spring of 2018, the Company began an approximate 12-week outage at East Bend to perform some significant, albeit routine, refurbishing of the station's boiler and precipitator.[333] This work is typical for a station of the approximate age of East Bend in order to continue to maintain its reliability and long-term operation.[334] The Company uses a five-year planning horizon for scheduling planned outages.[335]

The Company's forecasted test period budget for outage maintenance expense for East Bend and Woodsdale have been adjusted to reflect a normalized *(i.e.*, average) level of expense.[336] As part of the Application, outage maintenance expense was normalized based upon four years of actual maintenance expense and two years of projected maintenance expenses.[337]

While Mr. Kollen agrees that some amount of planned outage expense should be included in Duke Energy Kentucky's base rates,[338] he recommends reducing the Company's revenue requirement by $1.203 million based upon his usage of a different data set.[339] Once again, Mr. Kollen is using selective data to support his position,[340] which is both unfortunate and unfair. The Company's estimate is reasonable and should be approved.

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[331] *See id.*

[332] *See id.*; Company Response to AG DR-01-010.

[333] *See* Miller Direct, p. 8.

[334] *See id.*

[335] *See* Company Response to Staff DR-01-012.

[336] *See* Application, ¶ 43.

[337] *See id.*

[338] *See* Kollen Direct, pp. 16-17. Mr. Kollen's recommendation to reject the establishment of a deferral account to track the incremental costs of the Company's planned O&M expenses is addressed in Section III.F.1., *infra.*

[339] *See* Kollen Direct, p. 17.

[340] To the extent that Mr. Kollen chooses to ignore data that could be considered an outlier, he should have ignored years in which a $0 expense was projected.

e. Compensation Adjustments

The only witness to offer testimony in opposition to the Company's compensation expense was Mr. Kollen. However, he lacks the background, experience, training or knowledge to offer authoritative testimony as an expert on such matters. Mr. Kollen has never performed an analysis of how Duke Energy Kentucky's compensation plans compare to the market,[341] nor did he perform a wage and compensation study in this case.[342] He has not served as a human resources professional for any utility,[343] nor has he received training in developing and administering human resource policies.[344] Mr. Kollen is singularly unqualified to render an expert opinion on compensation policies and his testimony on this issue should be disregarded as a result.[345]

i. Compensation Must be Viewed as a Sum, Not as Discrete Parts

Duke Energy's compensation philosophy and policies are designed to be market based and competitive, and ensure that employees are not encouraged to take excessive or inappropriate risks.[346] The components of the compensation package, including base, variable incentives, and benefits, and in the aggregate, are targeted to deliver total compensation that is competitive with the applicable peer group and consistent with performance.[347] Disallowing recovery of a portion of the Company's compensation program would render the Company's compensation uncompetitive with the market, which would result in the inability to attract the talent the Company needs to run a safe, efficient and reliable electric system.[348] From the perspective of prudently and

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341 *See* HVR 4:15:03 (Mar. 8, 2018).

342 *See id.*, 4:15:50.

343 *See id.*, 4:16:20.

344 *See id.*, 4:16:40.

345 *See Miller v. Eldridge,* 146 S.W.3d 909 (Ky. 2004); *Burton v. CSX Transp., Inc.,* 296 S.W.3d 1 (Ky. 2008).

346 *See* Thomas Silinski Rebuttal Testimony (Silinski Rebuttal), p. 2 (filed Feb. 14, 2018).

347 *See id.*

348 *See id.*, p. 3.

efficiently managing the Company's retail electric business to the benefit of consumers and the public, there is no reasonable basis to deny recovery of employees' market-based compensation.[349]

If the Companies did not provide incentive opportunities to their employees, the same target value of incentive compensation would need to be added to base pay in order to maintain market-competitive compensation for its employees.[350] Thus, whether it is in base pay or a combination of base pay and incentives, Duke Energy Kentucky must keep its total compensation package competitive in order to attract and retain a competent workforce.[351] Market competitive compensation is a proper and reasonable expense that is allowable in base rates. Even Mr. Kollen agreed that it is unreasonable to expect that utility employees should have the exact same benefits across the Commonwealth,[352] and acknowledged that the sum of all wages and benefits is the best measure for determining a company's true compensation expense.[353] A one-size-fits all approach to authorizing recovery of utility compensation and benefits expenses is unreasonable, arbitrary and capricious.[354]

ii. Incentive Compensation

During discovery, the Company indicated that total test period incentive compensation incurred by Duke Energy Kentucky or allocated to it from its affiliates based on its financial performance as measured by earnings per share is $1,353,871.[355] However, Mr. Kollen

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[349] *See id.*

[350] *See* Company Response to Staff DR-03-025b.

[351] *See id.*

[352] *See* HVR 4:18:15 (Mar. 8, 2018).

[353] *See id.*, 4:17:50.

[354] *See In the Matter of: Carl Pippin v. Shelby Energy Cooperative, Inc.*, Order, Case No. 2011-00046, p. 7 (Ky. P.S.C. Apr. 4, 2011) ("The Commission does not micro-manage utilities and does not analyze the need for, or reasonableness of, utility expenditures outside of rate cases absent a showing that continuity of service may be in jeopardy.").

[355] *See* Company Response to Staff DR-03-025a.

recommends a negative $1.638 million adjustment.[356] The Commission has generally excluded incentive compensation tied to financial performance unless there is a clear nexus between the incentive and benefits for customers. In this case, such a clear nexus exists. In order to achieve financial targets, utility managers inherently manage costs – which directly benefits customers.[357] Yet, while achieving these financial targets, the utility must still operate reliably and safely. Financial-based incentives such as those offered by the Company directly benefit customers and should be recognized as a legitimate labor cost.

As part of his proposed adjustment, Mr. Kollen recommends that the Commission disallow recovery of an additional $541,424 in costs tied to the Company's issuance of Restricted Stock Units (RSUs) on the basis that they were a form of incentive compensation tied to overall corporate financial performance.[358] However, at the hearing, Mr. Kollen acknowledged that he had either overlooked or ignored the note at the bottom of Exhibit LK-10 (upon which he relied).[359] His efforts on the stand to spontaneously create a nexus between the issuance of RSUs and Duke Energy's earnings per share incentives fell flat and was unpersuasive.[360] Plainly, the exhibit states that the RSUs are a form of compensation designed exclusively to retain and attract employees and are *not* related to the Company's financial performance.[361]

Excluding the cost of RSUs from the Company's revenue requirement would deprive it of the ability to recover the cost of incentivizing employees to remain with the Company. The Company has a legitimate interest in attracting *and retaining* a skilled workforce as this directly

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[356] *See* Kollen Direct, pp. 18-21.

[357] *See* Silinksi Rebuttal, p. 6.

[358] *See* Kollen Direct, p. 18-20.

[359] *See* HVR 4:10:43 (Mar. 8, 2018).

[360] *See id.*, 4:12:10.

[361] *See* Silinski Rebuttal, pp. 7-8.

benefits customers through the accumulation of experience and knowledge.[362] The RSU program is one way the Company is able to accomplish this objective at a reasonable cost. Thus, even if the Commission chose to disallow recovery of incentive compensation tied to financial performance, the AG's recommendation to eliminate RSU expense is not supported by evidence and is entirely unreasonable.

iii. Retirement Compensation

Mr. Kollen's recommendation to exclude $1.584 million of the Company's test year retirement benefit expense should also be rejected. Again, Mr. Kollen's proposed adjustment lacks any analysis or justification.[363] His reliance upon Commission Orders in two other cases bears no relationship to the specific facts of Duke Energy Kentucky's financial position and he himself admitted that any statewide policy whereby utility employees have the exact same benefits would be unreasonable.[364] One must assume that the Commission's actions in the prior cases was based solely upon the facts in the record of those proceedings.

Again, the value of the Company's <u>total</u> compensation expense is what is important, rather than whether the Company chooses to deliver the value through multiple components. Mr. Kollen offers no support whatsoever that the benefit being provided from these plans is not market competitive. He also ignores the fact that Duke Energy Kentucky has significantly reduced retirement-related expenses by transitioning many employees eligible for pension benefits to a less rich formula and partially utilizing those pension savings to enhance 401(k) matching formulas.[365] The Company's benefit packages, including retirement programs, as a whole are designed to be

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[362] *See* Company Response to Staff DR 03-025b.

[363] *See* Silinski Rebuttal, p. 9.

[364] *See id.*

[365] *See id.*

market competitive and are benchmarked to ensure that is the case. Mr. Kollen does not, and cannot, dispute this.

Duke Energy Kentucky has aggressively managed costs related to its retirement benefit program by closing the defined benefit pension plan to new hires, and, for existing employees, freezing final average pay benefit formulas for all non-union employees and transitioning employees from a final average pay formula to a more "Defined Contribution like" cash balance pension formula. To offset the impact of those pension changes, the Company utilized some of the pension savings to enhance the 401(k) matching formula for those employees to stay competitive with the market. To arbitrarily eliminate recovery of retirement cost because some employees have benefits under both plans, would penalize the Company for aggressively managing its retirement costs. It would be absurd to adopt a policy – as Mr. Kollen does – whereby the Company would incur higher retirement costs by retaining a single retirement benefit plan.

Like all prudent and cost-minded companies that offer benefit packages that include retirement programs for employees, Duke Energy Kentucky continually evaluates these programs for cost and reasonableness.[366] As these programs change and evolve over time, it must be done in a manner that is fair to employees who make employment decisions based upon the existence of such plans. To arbitrarily require the Company to cease funding programs that current or retired employees previously participated in and relied upon is unreasonable and unfair to those employees.[367] Moreover, it also provides a significant disincentive for the Company to consider and pursue opportunities to revisit programs and follow market trends and implement new programs that will overall reduce its expenses.[368] The Commission should encourage utilities to

[366] *See id.*, p. 10.

[367] *See id.*

[368] *See id.*

proactively manage their costs, not discourage and penalize them by excluding such initiatives from recovery. The Company's retirement benefits are reasonable and, therefore, the AG's recommendation to disallow same should be rejected.

iv. Workforce Turnover

Experience shows that the Company's current total compensation levels are not adequate to prevent abnormally-high workforce turnover.[369] According to the Bureau of Labor Statistics (BLS), the average annual total separations for companies in the trade, transportation, and utilities industry was 3.9% for 2015, 3.7% for 2016 and 3.7% for 2017.[370] Duke Energy Kentucky experienced higher attrition in two out of three of these years, at 7.9%, 10.2% and 3.7%, respectively.[371] The 3-year average for the BLS is 3.76%, while Duke Energy Kentucky averaged 7.26%, almost double the attrition rate over the same period of time.[372]

If the Commission disallows cost recovery for the Company's current package of pay and benefits, the Company would most certainly fall below market-competitive levels.[373] This would have substantial negative implications for the cost of service to customers and would be imprudent.[374] The length of time necessary to fully train employees to safely perform all aspects of their job, the expense incurred to hire and train new employees and the loss of productivity realized through high turnover rates would all negatively affect the ability of the Company to provide safe and reliable service at a reasonable cost.[375] This is also true for leadership positions.[376]

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[369] *See id.*, p. 4.
[370] *See id.*
[371] *See id.*
[372] *See id.*
[373] *See id.*
[374] *See id.*
[375] *See id.*, p. 5.
[376] *See id.*

Duke Energy invests in developing highly effective leaders who carry out the organization's mission and inspire employees to work together to achieve results the right way.[377] Paying less than competitive levels of compensation would put the Company at risk of losing these valuable leaders to other companies and potentially having to pay more to attract the same level of leadership talent externally.[378] The financial cost of turnover and negative implications from lost productivity, hiring, training and job vacancy can put a significant level of productivity and financial value at risk to the Company.[379] Compensation is similar to the other costs related to producing and distributing electricity.[380] It is a necessary cost to provide customers safe and reliable service.[381] In the competitive market for talent, employees consider total rewards, including base pay, incentive pay and benefits, as a key determinant in deciding whether to work for a particular employer.[382] The target incentive compensation provided by Duke Energy is necessary to achieve market-competitive compensation and, thus, is a reasonable and appropriate cost of doing business that should not be eliminated.[383]

In contrast, Mr. Kollen provided little justification, support, or analysis in making his recommended adjustment. He offers no claim that the Company's compensation, including portions of the incentive package that are tied to corporate financial performance, are anything but market-based and competitive. Mr. Kollen's opinion does not qualify as an expert opinion and his recommendation should be rejected.

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[377] *See id.*

[378] *See id.*

[379] *See id.*

[380] *See id.*

[381] *See id.*

[382] *See id.*

[383] *See id.*

f. Other Adjustments

i. PJM Make Whole and Other Revenues

Mr. Kollen originally suggested that the Commission should include PJM Make-Whole payments and other ancillary service market revenues as an offset to the Company's revenue requirement.[384] As was later acknowledged, however, his recommendation did not take into account the fact that such revenues are already fully accounted for in the Company's Rider PSM and Rider FAC.[385] Accordingly, Mr. Kollen appropriately withdrew his proposal.[386] Based upon this concession, the Commission should reject the AG's proposed adjustment.

ii. AMI Levelization Expense Amortization

In accordance with the Commission Order in Case No. 2016-00152,[387] Duke Energy Kentucky is proposing an adjustment to its test year revenue requirement to bring forward certain benefits it projected would result from its AMI deployment.[388] The AG challenges the Company's adjustment and claims that it is not generous enough.[389] However, the Company only made two changes between the illustrative calculation provided by the Company in Case No. 2016-00152,[390] and the calculation tendered with the Application in this case: (1) the calculation was updated to reflect the fact that the Company filed a base rate case earlier than originally anticipated; and 2) the calculation was updated to reflect the delay in the project deployment due to the timing of the

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[384] *See* Kollen Direct, pp. 6-8.

[385] *See* Wathen Rebuttal, pp. 2-3; AG Response to Company DR-01-036.

[386] *See* AG Response to Company DR DR-01-033 and 034; AG Response to Staff DR-01-002.

[387] *See In the matter of: Application of Duke Energy Kentucky, Inc. for (1) A Certificate of Public Convenience and Necessity Authorizing the Construction of an Advanced Metering Infrastructure; (2) Request for Accounting Treatment; and (3) All Other Necessary Waivers, Approvals, and Relief.* Order, Case No. 2016-00152 (Ky. P.S.C. May 25, 2017).

[388] *See* Wathen Direct, p. 9; Wathen Rebuttal, p. 8; *see also* Company Response to AG DR-01-077 (describing overall cost management in the deployment project).

[389] Kollen Direct, pp. 21-23.

[390] *See* Case No. 2016-00152, Company's Confidential Response to AG DR-02-035(c).

Commission's approval of the Company's AMI application occurring in May 2017.[391] Mr. Kollen's calculation uses a different methodology by incorporating projected savings over the full fourteen-year period, while totally ignoring the projected costs over the same period.[392] If the shoe was on the other foot and the Company had used only incremental costs to calculate the AMI levelization expense, the AG would have objected mightily. While Mr. Kollen has consistently been self-servingly selective in the data that he uses to arrive at his revenue requirement adjustment recommendations, this particular example is unreasonable.

There are other basic errors in Mr. Kollen's methodology. First, his recommendation does not even pass the basic mathematical accuracy test as he uses fourteen years of data while claiming to use fifteen years.[393] Second, he relied upon a document that was filed as part of the record in Case No. 2016-00152, which included an estimated AMI deployment schedule.[394] That schedule, of course, was a proposal and, due to the timing of the final resolution of that case, proved to be too optimistic.[395] Rather than use an accurate AMI deployment schedule that was provided to Mr. Kollen as part of this case,[396] he purposefully used an out-of-date schedule to skew the results of his analysis.[397] Mr. Kollen's lack of consistency and accuracy completely undercuts any

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391 *See* Wathen Rebuttal, pp. 8-9.

392 *See id.*, p. 9.

393 *Compare* Kollen Direct, pp. 22-23 *and* Wathen Rebuttal, pp. 9-10.

394 *See* Wathen Rebuttal, p. 10.

395 *See id.*, p. 9. The Commission's May approval of the Company's CPCN was later than what was anticipated in the Company's application in Case No 2016-00152. As a result, the Company's actual AMI deployment is significantly later than the plan submitted in the cost-benefit analysis submitted in that case.

396 *See* Company Response to AG DR-02-035(c) Confidential Attachment.

397 In his rebuttal testimony, Mr. Wathen used the methodology used by Mr. Kollen, but without Mr. Kollen's computational and data set errors. The Company does not agree that Mr. Kollen's methodology should be used, but if the Commission chooses to adopt it and, in essence, undue the Company's proposed methodology from case No. 2016-00152, the result would be to make an adjustment to the Company's revenue requirement that is higher than that proposed by the Company, but lower than that proposed by Mr. Kollen. This corrected adjustment is explained by Mr. Wathen as follows:

> So, Mr. Kollen's adjustment for AMI savings, when corrected, results in an adjustment to test year revenue requirement of $3,176,520. That figure is higher

credibility he might otherwise bring to bear on this and similar issues. The AG's recommendation is unreasonable and inaccurate and should be summarily rejected.

iii. RTEP Expense

The Company originally proposed an adjustment to its revenue requirement to account for PJM Regional Transmission Expansion Planning (RTEP) expense.[398] Mr. Kollen proposed an adjustment to the Company's calculation,[399] which the Company believes is reasonable.[400] Accordingly, the Company agrees to reduce its test year revenue requirement by $410,346 to reflect lower forecasted RTEP expenses.[401]

iv. Vegetation Management Expense

The purpose of the Company's vegetation management program is to "control the growth of incompatible vegetation along its electric lines in order to help provide safe and reliable service to customers."[402] The Company must currently inspect approximately 320 miles of lines each year to timely cycle through its 1,441 miles of overhead distribution lines.[403] Due to the proximity to energized power lines, Duke Energy Kentucky's vegetation management contractors must be properly trained.[404] The Company utilizes a Request for Proposal (RFP) process to assure that it finds contractors that are able to provide the best service as the least cost.[405] This requires the

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> than the amount included in the Company's application, of $2,321,137, but lower than Mr. Kollen's incorrect calculation of $3,684,481. Therefore, the maximum adjustment the Commission should make to the Company request is $855,383 ($3,176,520 - $2,321,137) rather than Mr. Kollen's adjustment of $1,363,344.

Wathen Rebuttal, p. 11, Confidential WDW-Rebuttal-2.

[398] *See* Pratt Direct, p. 21.

[399] *See* Kollen Direct, pp. 13-14.

[400] *See* Lawler Rebuttal, p. 5.

[401] *See id.*

[402] April Edwards Rebuttal Testimony, p. 3 (filed Feb. 14, 2018).

[403] *See id.*, p. 4.

[404] *See id.*, p. 6.

[405] *See id.*

Company to examine bidders' expertise, resources, safety record and pricing.[406] Moreover, the market for vegetation management services is not confined to the Company's service territory and it must compete with utilities in Kentucky, Indiana, Ohio and other Midwestern states.[407]

Recently, however, the local market for vegetation management services has contracted and it has been necessary for Duke Energy Kentucky to acquire services from a larger market.[408] At the end of 2016, the Company's vegetation management contractor informed Duke Energy Kentucky that it was no longer able to provide the resources necessary to fulfill the Company's vegetation management plan.[409] To give it more flexibility in meeting its obligations, the Company is proposing to shift to a 5-year trimming cycle instead of a 4.5-year trimming cycle as a cost-saving measure.[410] It has also partnered with sister utilities to achieve greater economies of scale.[411] Nevertheless, vegetation management expense has nearly tripled and is expected to continue to rise by 3% - 5% each year.[412]

The result is that Duke Energy Kentucky's test year distribution vegetation management expense is $4.036 million and total forecasted test year expense that includes both distribution and transmission in $4.480 million.[413] On behalf of the AG, Mr. Kollen proposed reducing Duke Energy Kentucky's vegetation management costs by $2.4 million, which results in a reduction in

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[406] *See id.*

[407] *See id.*, p. 14.

[408] *See id.*, p. 6; Company Response to Staff-DR-03-014a.

[409] *See* Edwards Rebuttal, p. 7.

[410] *See id.*, pp. 3, 8.

[411] *See id.*, pp. 16-17.

[412] *See id.*, p. 15.

[413] *See id.*, p. 9.

the Company's revenue requirement of $2.407 million.[414] Mr. Kollen was unaware, however, of the Company's obligation to maintain and observe a vegetation management plan.[415]

Mr. Kollen's proposal is unreasonable for the simple fact that it once again conveniently ignores all the relevant data that fully justifies the vegetation management expense included in the Company's Application. Mr. Kollen considered only the data available for 2012-2016,[416] which was before the Company was notified that its existing contractor could no longer perform to the standards required by the Company's vegetation management plan. He was unaware of the Company's actual vegetation management expense for 2017,[417] and chose not to take into account the actual bid estimates for 2018 vegetation management expense,[418] even though it had previously been provided by the Company.[419] Mr. Kollen conceded that he had no basis to dispute the reasonableness of the Company's RFP process.[420]

Mr. Kollen's self-serving, cherry-picking of data is demonstrated by his: (1) relying upon data that is known to be outdated; and (2) ignoring data that is based upon a recent RFP process.[421] There is *no evidence* to support Mr. Kollen's proposition that the Company's vegetation management expense in the test year and thereafter will be similar to its expense from 2012-2016. In fact, all of the evidence conclusively points to the contrary – the cost of vegetation management has increased exponentially due to a constriction in the number of providers able to perform such

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[414] *See* Kollen Direct, pp. 5, 15.

[415] *See* AG Response to Company Request 01-050. The Commission ordered Duke Energy Kentucky to develop and maintain a vegetation management plan in 2007. *See In the Matter of: An Investigation of the Reliability Measures of Kentucky's Jurisdictional Electric Distribution Utilities and Certain Reliability Maintenance Practices*, Order, Case No. 2006-00494 (Ky. P.S.C. Oct. 26, 2007).

[416] *See* Kollen Direct, p. 15; AG Response to Company DR-01-048 and 049; Edwards Rebuttal, p. 10.

[417] *See* HVR 3:56:35 (Mar. 8, 2018).

[418] *See id.*, 3:48:40.

[419] *See* Company Response to AG-DR-02-001; Edwards Rebuttal, p. 11.

[420] *See* HVR 3:58:35 (Mar 8, 2018).

[421] *See* Edwards Rebuttal, p. 12.

services. The willful ignorance of relevant data that is known and measurable is anathema to the ratemaking process. Adopting Mr. Kollen's recommended adjustment results in the Company's vegetation management budget to be underfunded and insufficient to meet its required annual trimming. The only way the Company could manage its expenses to the level suggested by Mr. Kollen would be to further expand its trim cycle from five years to a significantly longer cycle, almost twice as long, at a substantial risk to providing reliable and reasonable service. Accordingly, Mr. Kollen's proposed vegetation management adjustment should be rejected.

v. Research Tax Credits Amortization

As part of its Application, the Company proposed to recover certain research tax credits.[422] Mr. Kollen recommended that an adjustment be made to eliminate the research tax credits from the calculation of income taxes.[423] The Company agrees with Mr. Kollen's recommendation and has withdrawn this portion of its request.[424] As set forth in Ms. Lawler's rebuttal testimony, $119,514 should therefore be reduced from the Company's revenue requirement.[425]

vi. Carbon Management Research Group Amortization

The Company originally proposed an adjustment to the forecasted test year on Schedule D-2.31 to amortize the Carbon Management Research Group Regulatory Asset over a five-year period.[426] The Company obtained authorization from the Commission to defer these costs for accounting purposes in Case No. 2008-00308.[427] The Company's application in that case stated

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[422] *See* Lawler Direct, p. 13.

[423] *See* Kollen Direct, p. 49.

[424] *See* Bellucci Rebuttal, p. 6.

[425] *See* Lawler Rebuttal, p. 4.

[426] *See* Lawler Direct, p. 13.

[427] *See In the Matter of the Joint Application of Duke Energy Kentucky, Inc., Kentucky Power Company, Kentucky Utilities Company and Louisville Gas and Electric Company for an Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities Related to Certain Payments made to Carbon Management Research Group and the Kentucky Consortium for Carbon Storage*, Order, Case No. 2008-00308 (Ky. P.S.C. Oct. 30, 2008).

the intent to amortize this regulatory asset over a ten-year period. As such, the Company is modifying its revenue requirement to reflect a ten-year amortization period.[428] The effect of the adjustment is a $200,551 reduction to the Company's requested revenue requirement.[429] Capitalization has also been updated to reflect the reduction in amortization expense.[430] The effect of the adjustment to capitalization is a $17,612 increase to the Company's requested revenue requirement.[431]

4. Rate of Return

a. Capitalization Ratio and Current Rates of Return

The Company is proposing a capitalization comprised of 51.1% debt and 48.9% equity.[432] This balance is appropriate as it introduces an appropriate amount of risk due to leverage and minimizes the WACC to customers.[433] The Company's return on equity (ROE) is forecasted to decline from 10.13% in 2016 to 8.21% in the base period due to a decrease in net income that largely resulted from favorable income tax adjustments in 2016 that are not expected to reoccur in the base period.[434] The erosion in ROE accelerates to 3.93% in the forecasted period due to a decrease in net income attributable to increased depreciation, interest expense and costs for planned plant outages.[435] Likewise, short-term debt rates are expected to increase from 2.062% as of November 2017 to an average of 3.083% for the forecast period.[436] Long-term debt rates are

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[428] *See* Lawler Rebuttal, p. 5.

[429] *See id.*, p. 5.

[430] *See id.*

[431] *See id.*

[432] *See* Sullivan Direct, p. 4.

[433] *See id.*, p. 8.

[434] *See* Company Response to Staff-DR-02-006b.

[435] *See* Company Response to Staff-DR-02-006c.

[436] *See* Sullivan Direct, p. 11.

expected to marginally decrease from 4.253% to 4.243% for the same periods.[437] The Company's proposed capitalization ratio has not been challenged by any of the intervenors and should be approved.

b. Investor Expectations

A utility's credit rating is the result of an overall assessment of several qualitative and quantitative factors which measure investor expectations for a class of debt or equity. Qualitative aspects may include Duke Energy Kentucky's regulatory climate, its track record for delivering on its commitments, the strength of its management team, corporate governance, its operating performance, and its service territory.[438] Quantitative measures are primarily based on operating cash flow and focus on Duke Energy Kentucky's ability to meet its fixed obligations (interest expense in particular) on the basis of internally generated cash and the level at which Duke Energy Kentucky maintains debt balances.[439] The percentage of debt to total capital is another example of a quantitative measure.[440] Challenges facing the Company that have been identified by the credit agencies include increasing capital expenditures (particularly for environmental compliance) and Duke Energy Kentucky's relatively small size compared to other integrated utilities.[441]

Investors, investment analysts, and the rating agencies regard regulation as one of the most important factors in assessing a utility company's financial strength.[442] These stakeholders want to be confident a utility company operates in a stable regulatory environment that will allow the company to recover prudently incurred costs and earn a reasonable return on investments necessary

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[437] *See id.*

[438] *See id.*, p. 5.

[439] *See id.*

[440] *See id.*

[441] *See id.*, p. 8.

[442] *See id.*, p. 5.

to meet the demand, reliability, and service requirements of its customers.[443] Important considerations include the allowed rate of return, cash quality of earnings, timely recovery of capital investments, stability of earnings, and the strength of its capital structure.[444] Positive consideration is also given for utilities operating in states where the regulatory process is streamlined and outcomes are equitably balanced between customers and investors.[445]

Customers benefit from a utility having a favorable credit rating, including lower overall financing costs and greater access to credit markets.[446] Currently, the Company has an "A-/Stable" Senior Unsecured Rating from Standard & Poor's.[447] At the time the case was filed, the Company had a "BAA1/Stable" Outlook from Moody's Investor Services;[448] however, Duke Energy Corporation's outlook was recently changed from "Stable" to "Negative" in light of the potentially negative impacts of the Tax Act.[449] This is an indication that the Company's rates must be adjusted before the Company experiences significant financial consequences in the form of higher borrowing costs and less access to capital markets.

c. The Company's Proposed Return on Equity will Reasonably Compensate Investors

To evaluate what would be an appropriate ROE, the Company retained the expert who literally wrote the book on utility finance, Dr. Roger A. Morin, Ph.D.[450] Dr. Morin performed an analysis of the Company's cost of capital by using three methodologies: (1) Discounted Cash Flow

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443 *See id.*, p. 6.

444 *See id.*

445 *See id.*

446 *See id.*, p. 4.

447 *See id.*, p. 6.

448 *See id.*

449 *See* Company Response to Staff Post-Hearing DR-01-006, Attachment 2.

450 Dr. Morin's qualifications and expertise are unquestioned. He is recognized as world-renown expert on utility finance and has offered testimony in vast and diverse contexts and venues. *See* Roger A. Morin, Ph.D. Direct Testimony (Morin Direct), Attachment RAM-1 (filed Sep. 1, 2017).

(DCF); (2) Capital Asset Pricing Model (CAPM); and (3) Risk Premium (RP).[451] The DCF method holds that the value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits.[452] After extensively describing his methodology,[453] Dr. Morin arrived at a DCF-driven ROE of between 9.03% and 9.44%.[454] The CAPM differs in methodology from the DCF in that it assumes risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities.[455] Thus, the CAPM quantifies the additional return, or risk premium, required for bearing incremental risk and, thereby, provides a formal risk-return relationship anchored on the basic idea that only market risk matters.[456] Using both a traditional CAPM and an empirical CAPM analysis, Dr. Morin concluded that an appropriate ROE would be between 9.5% and 10.0%.[457] Finally, Dr. Morin used the RP methodology to examine the actual realized return on equity capital for the S&P Utility Index for each year, using the actual stock prices and dividends of the index, and then subtracting the long-term Treasury bond return for that year.[458] This analysis yielded an ROE range of 10.5% to 10.7%.[459]

Dr. Morin concluded that an appropriate ROE would be within the range of "9.9% - 10.7%."[460] The result was determined "in order to account for Duke Energy Kentucky's high external financing risks relative to its very small size, a substantial increase in interest rates

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[451] *See* Morin Direct, p. 5.

[452] *See id.*, p. 19.

[453] *See id.*, pp. 19-31.

[454] *See id.*, p. 31.

[455] *See id.*, pp. 31-32.

[456] *See id.*, p. 32.

[457] *See id.*, p. 48.

[458] *See id.*

[459] *See id.*, p. 53. Each of Dr. Morin's calculations included an adjustment for flotation costs.

[460] *See id.*, p. 4.

predicted over the next several years, a highly concentrated generation mix, and a higher degree of regulatory risk."[461] Elaborating on these considerations, Dr. Morin explained:

> First, the Company is projected to raise very large sums of money in a rising interest rate environment over the next five years relative to its small size. High business risks result from a large infrastructure-related capital investment plan relative to the size of the Company's rate base and common equity capital base, coupled with regulatory uncertainties. The Company's ambitious capital expenditure program which will require approximately $710 million of financing over the next five years for new utility infrastructure investments in order to improve reliability, upgrade the distribution and transmission infrastructure, and enhance reliability. To place that number in proper perspective, the Company's common equity balance (ownership capital) is approximately $1,051 million. In other words, the company is expected to spend an amount which represents more than one half of its entire common equity ownership capital.
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> Because of the Company's large construction program over the next few years, rate relief requirements and regulatory treatment uncertainty will increase regulatory risks as well. Generally, regulatory risks include approval risks, lags and delays, potential rate base exclusions, and potential disallowances. Continued regulatory support from the Commission will be required. Reviews of the economic and environmental aspects of new construction can consume as much as one year before approval or denial. Uncertainty of approval increases forecasting and planning risks and complicates the utility's ability to devise optimum electric distribution-transmission networks. Regulatory approval for financings required for new construction may also be required, injecting additional risks. ...
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> The second reason is the Company's very small size. Duke Energy Kentucky is one of the smallest electric utilities in the industry on the basis of revenues, capital base, and number of customers. The Company's very small size must also be considered in arriving at the cost of common equity. Duke Energy Kentucky possesses very small revenue and asset bases, both in absolute terms and relative to the other electric utilities in the comparable group. Investment risk increases as company size diminishes, all else remaining constant. The size phenomenon is well documented in the finance literature, and is fully discussed in Chapter 6 of my book *The New*

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[461] *See id.*, p. 4.

> *Regulatory Finance* and is also fully discussed in the Duff & Phelps Valuation 2016 Yearbook which devotes two full chapters and two appendices documenting and quantifying the size effect. The gist of the literature is that small companies have very different returns than large ones and on average those returns have been higher. The greater risk of small stocks does not fully account for their higher returns over many historical periods. The average small stock premium is well in excess of that of the average stock, more than could be expected by risk differences alone, suggesting that the cost of equity for small stocks is considerably larger than for large capitalization stocks. In addition to earning the highest average rates of return, small stocks also have the highest volatility, as measured by the standard deviation of returns.
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> The third reason is the risk related to the Company's generation concentration and lack of resource diversity. The Company generation requirements are met with only one single coal-fired generating station which supplies all base load requirements, with little to no reserve capacity. A costly combustion turbine accommodates peak load requirements, but at very high costs.[462]

Given the ubiquity of similar riders and cost trackers in the utility industry nationwide, Dr. Morin's recommendation did not change even when the approval of Rider FTR, Rider DCI and Rider PSM were considered.[463] Dr. Morin explained that allowing an ROE below that of his recommendation would ultimately "increase costs for ratepayers."[464]

Based upon Dr. Morin's expert and skilled analysis, the Company is requesting a 10.3% allowed return on equity in this case.[465] The requested return will allow Duke Energy Kentucky to compensate equity investors for the risk of their investment by targeting fair and adequate returns, a stable dividend policy, and earnings growth – all of which are necessary to preserve ongoing access to equity capital.[466] Returns to equity investors are realized only after all operating

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[462] *Id.*, pp. 63-66.

[463] *See id.*, pp. 58-60.

[464] *See id.*, pp. 5. 14-16.

[465] *See* Sullivan Direct, p. 9.

[466] *See id.*

expenses and fixed payment obligations (including debt principal and interest) of the Company have been paid.[467] Because equity investors are the last in priority to a company's assets, their investment is most at risk should the company suffer any underperformance.[468] For this reason, equity investors require a higher return on investment. Equity investors expect utilities like Duke Energy Kentucky to recover their prudently incurred costs and earn a fair and reasonable return for their investors.[469]

The requested return is also consistent with several other factors which indicate a return higher than that which the Commission has recently approved is reasonable in this case. For example, unlike in other recent cases, interest rates have risen and are widely-expected to continue to rise in the short term. In fact, Jerome H. Powell, Chairman of the Board of Governors of the Federal Reserve System recently testified before the Committee on Financial Services of the U.S. House of Representatives indicated that further gradual increases in the federal funds rate are likely.[470]

Likewise, other regulatory agencies around the country have noted the uptick in investor expectations for returns on equity and have responded to market conditions by authorizing higher returns.[471] Failing to do so, investor capital goes to other utilities and other industries.

d. The Attorney General's Proposed ROE is Patently Unreasonable

Mr. Baudino, on behalf of the AG, recommends that the Commission authorize a ROE of 8.8%.[472] However, the sheer number of errors and gross assumptions in his direct testimony render

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[467] *See id.*

[468] *See id.*

[469] *See id.*

[470] *See* HVR 00:30:49 (Mar. 8, 2018).

[471] *See id.* 00:47:40.

[472] *See* Richard Baudino Direct Testimony (Baudino Direct), p. 3 (filed Dec. 28, 2017).

his recommendation *void ab initio*. In particular, Mr. Baudino's analysis is subject to criticism in nine specific areas: (1) a recommended return outside the mainstream of such analysis; (2) the inexplicable failure to use different analytical methodologies; (3) an understated dividend yield component in the DCF model; (4) the absence of a flotation cost adjustment in his DCF analysis; (5) the use of the less common dividend growth version of the DCF model instead of the commonly used earnings growth version of the DCF model; (6) the use of an inappropriate risk-free rate proxy in the CAPM; (7) an erroneous calculation of his market risk premium estimate in the CAPM; (8) the failure to employ the empirical version of the CAPM in keeping with the vast body of literature on the subject; and (9) the failure to account for Duke Energy Kentucky's high relative risks.

First, Mr. Baudino's recommended 8.8% ROE "is draconian and lies completely outside the zone of reasonableness and outside the zone of currently authorized ROEs for electric utilities in the United States."[473] As demonstrated, the average ROE for vertically integrated utilities across the country for 2017 was 9.8%.[474] Mr. Baudino conceded that his own recommendation was below any other authorized ROE 2017 for vertically integrated utilities that included generation.[475] In fact, Mr. Baudino's recommendation is below the zone of his own comparable companies' authorized and expected ROEs.[476] The recommendation is so low that it is itself the best evidence that Mr. Baudino's testimony lacks credibility. Second, Mr. Baudino's analysis lacks intellectual rigor. He only performed a DCF analysis,[477] which is uncharacteristic of a financial professional who recognizes the value of using multiple methodologies in their analysis. Mr. Baudino's use of the CAPM as a "check" on his DCF analysis is not the purpose for which the CAPM is intended.

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[473] *See* Roger A. Morin, Ph.D. Rebuttal Testimony (Morin Rebuttal), p. 2 (Feb. 14, 2018).

[474] *See* Company Confidential Hearing Exhibit 5, p. 1; HVR 00:47:30 (Mar. 8, 2018).

[475] *See* HVR 1:31:20 (Mar. 8, 2018).

[476] *See* Morin Rebuttal, p. 2. Mr. Baudino's peer group had an average ROE of 9.9% and a median ROE of 10.1%.

[477] *See id.*, pp. 3, 36-38.

And, at any rate, Mr. Baudino did not even apply the CAPM correctly.[478] Third, Mr. Baudino's DCF dividend yield component is understated because it is not consistent with the annual form of the DCF model. It is simply inappropriate to increase the dividend yield by adding one-half the future growth rate to the spot dividend yield.[479] This deviation causes the annual DCF model to give an unreliable outcome due to its failure to allow for the quarterly timing of dividend payments.[480] In short, Mr. Baudino's DCF results are understated by some 12 basis points alone related to this single flaw.[481] Fourth, Mr. Baudino further understated the dividend yield component by not allowing for flotation costs, thereby leaving a legitimate cost unrecovered.[482] This error induced another 20 basis point error into Mr. Baudino's analysis.[483] Fifth, Mr. Baudino errs by using a dividend growth forecast when such forecasts are comparatively rare.[484] Earnings forecasts provide a much more useful data point for such analysis and are the norm for such analysis in the marketplace.[485] Mr. Baudino's retention growth technique contains a logical inconsistency as he fails to use the full results of his approach or explain his basis for excluding the results.[486] Mr. Baudino's analysis in essence assumes the answer he is looking for,[487] which is a serious analytical error. Sixth, Mr. Baudino relies upon an inappropriate risk-free rate proxy in implementing his CAPM, resulting in a corresponding understatement of his results by nearly 200

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[478] *See id.*, p. 3.

[479] *See id.*, pp. 7, 11-12.

[480] *See id.*, p. 7.

[481] *See id.*

[482] *See id.*, pp. 7, 13-14.

[483] *See id.*, p. 7.

[484] *See id.*, pp. 7, 15-16.

[485] *See id.*, p. 7.

[486] *See id.*, pp. 8, 16-18.

[487] *See id.*, pp. 8, 18-19.

basis points.[488] Seventh, Mr. Baudino erroneously uses geometric mean returns rather than arithmetic mean returns when estimating the market risk premium (MRP) in the course of his CAPM "analysis."[489] Eighth, Mr. Baudino uses a simplistic version of the CAPM, which understates the cost of equity by another 50 basis points.[490] Ninth, Mr. Baudino failed to take into account the fact that Duke Energy Kentucky is a relatively small utility, it is facing a large construction program prospectively and it has a highly concentrated generation portfolio.[491]

Taken in isolation, any one of the foregoing deficiencies in Mr. Baudino's analytical methods would suggest that he has understated the necessary ROE. However, viewed in relation to one another, it is readily apparent that Mr. Baudino's analysis is intrinsically flawed. It is therefore no surprise that his opinion is well outside the mainstream and not credible. When Mr. Baudino's errors are corrected, and the most recent trends in interest rates and authorized ROEs are taken into account, the Company's requested 10.3% ROE is reasonable and should be approved.

5. The Company's Cost of Service Study is Reasonable

The Company tendered a Cost of Service Study (COSS) as part of its filing. The COSS was undertaken with two prior Commission mandates in mind, including: (1) the requirement to separate distribution plant into primary and secondary components;[492] and (2) the use of multiple demand allocation methods to develop a COSS.[493] The Company prepared three separate Class

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[488] *See id.*, pp. 8, 24-29.

[489] *See id.*, pp. 8. 22-24, 29-32.

[490] *See id.*, p. 8.

[491] *See id.*, pp. 8-9.

[492] *See In the Matter of the Application of the Union Light, Heat, & Power Company to Adjust Electric Rates*, Order, Case No, 1991-00370 (Ky. P.S.C. June 11, 1992); James E. Ziolkowski Direct Testimony (Direct Testimony). p. 3 (filed Sep. 1, 2017).

[493] *See id.*

Cost of Service Studies that contain essentially the same data, except that different methodologies were used to develop the allocation factor used for the demand component of production-related costs.[494] The demand allocation methods used are as follows: (1) the Average of the Twelve (12) Coincident Peaks (12-CP) method; (2) the Average and Excess (A&E) method; and (3) the Summer/Non-Summer (S/NS) method.[495]

The 12-CP method is the Company's preferred COSS methodology. The 12-CP method is designed to allocate capacity related costs to the customer classes using the system during maximum system load.[496] The allocation of capacity costs to each customer class is based on the class load contribution to the maximum peak, at the time of peak, regardless of their respective loads at other times of the day.[497] The Company requests the Commission to approve and use the 12-CP COSS in this case for three reasons: (1) it is generally accepted in the utility industry and was used in the Company's last rate case; (2) it recognizes that Duke Energy Kentucky's current generation fleet is designed to precisely meet the monthly maximum peak loads of customers; and (3) there is no compelling reason to adopt a new methodology.[498] Both the AG's witness, Mr. Watkins, and NKU's witness, Mr. Collins, agreed that the Company's 12-CP methodology was appropriate.[499]

In his testimony, Company witness, Mr. James Ziolkowski, provides an elaborate description of the process he used to develop the 12 CP COSS.[500] The COSS revealed that there

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[494] *See id.*, p. 5.

[495] *See id.*

[496] *See id.*, p. 6.

[497] *See id.*

[498] *See id.*, p. 7.

[499] *See* Glenn Watkins Direct Testimony (Watkins Direct), p. 22 (filed Dec. 28, 2017); Brian Collins Direct Testimony (Collins Direct), p. 2 (filed Dec. 29, 2017).

[500] *See* Ziolkowski Direct, pp. 8-25.

are significant differences among the rate classes when comparing the actual return earned by each rate class to the 7.08% overall return on capitalization being requested in this case.[501] Thus, in order to develop rates that generate the amount of revenue that equals the allocated revenue requirement for each rate class, it is necessary to have greater increases for some rate classes, in terms of percentage increases, than other classes.[502] In order to mitigate the rate shock that may come from completely eliminating the subsidy/excess (or rate disparities) among the rate classes, the Company proposes to use a two-step process to distribute the proposed revenue increase.[503] The first step eliminates 10% of the subsidy/excess revenues between customer classes based on present revenues.[504] The second step allocates the rate increase to customer classes based on electric distribution original cost depreciated (OCD) rate base.[505] Mr. Bieber, on behalf of Kroger, suggested that half of the reduction in the revenue requirement associated with the FIT reduction should be applied to all rate classes with the balance applied to reduce interclass subsidies,[506] which would principally mean customers receiving service under Rate RS. Mr. Bieber failed to cite a single authority to support his argument. Mr. Watkins, on behalf of the AG, however, agreed with the Company that the cost of service study reasonably assigns the incremental revenue requirement to the residential class under Rate RS.[507]

In the course of the hearing, Commission Staff requested the Company to make certain revisions to the Company's COSS to incorporate the changes resulting from the Tax Act.[508] The

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[501] *See id.*, p. 26.

[502] *See id.*, p. 26.

[503] *See id.*

[504] *See id.*

[505] *See id.*

[506] *See* Bieber Direct, pp. 4, 8-11.

[507] *See* Watkins Direct, p. 25; HVR 1:41:02 (Mar. 8, 2018).

[508] *See* HVR 2:33:42 (Mar. 7, 2018).

Company provided this information as requested.[509] Based upon the foregoing, the Company requests the Commission to accept the 12-CP COSS tendered herein, as updated.

6. Rate Design

In allocating the rate increase amongst the various rate classes, Duke Energy Kentucky was guided by several core principles. First, the Company designed rates that approximate the cost of providing service to each customer class.[510] Second, the Company intended to generally maintain the current rate structures to minimize impacts to each class.[511] Third, the customer charge is proposed to rise to a level that better reflects the fixed costs of serving customers within a class while keeping the Company's residential customer charge one of the lowest in the state.[512] Mr. Collins, testifying on behalf of NKU, agreed with the Company's proposed rate allocation on the basis that it adheres to the principle of gradualism.[513]

a. The Company's Proposed Customer Charges are Reasonable

Duke Energy Kentucky is proposing several increases in rate class customer charges to better reflect the fixed costs of serving customers within a class. Specifically, the Company is proposing customer charge increases for Rate Classes RS, DS (single phase service), DS (three phase service), DP, DT (single and three phase service) and DT (primary service).[514] Of these increases, the only one challenged by any intervenor was the increase to the customer charge for Rate RS and, even then, it was challenged only by AG witness Mr. Watkins.[515]

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[509] *See* Company Response to Staff Post-Hearing DR-01-008, Attachment.

[510] *See* Bruce L. Sailers Direct Testimony (Sailers Direct), p. 9 (filed Sep. 1, 2017).

[511] *See id.*, p. 10.

[512] *See id.*, p. 10.

[513] *See* Collins Direct, p.2.

[514] *See* Sailers Direct, pp. 10-11.

[515] *See* Watkins Direct, p. 27.

Mr. Watkins' concerns are unfounded. He first claims that increasing the customer charge will somehow cause the Company's rates to run afoul of the principles of competitive markets.[516] His argument holds as much water as a leaky bucket when one considers the fact that Duke Energy Kentucky's residential rates are the lowest of any investor-owned utility in Kentucky and the sixth lowest of any investor-owned electric utility in the nation.[517] Moreover, if one were to examine the Company's existing and proposed customer charge in isolation, it would be seen that the existing customer charge is the lowest, by a very large percentage, compared to any other regulated utility in Kentucky.[518] If the customer charge is approved as requested, Duke Energy Kentucky will still have a customer charge lower than twenty of the other twenty-four regulated electric utilities in the Commonwealth.[519] Clearly, the proposed customer charge is "competitive." There is nothing about any of these other utilities' provision of electric service that makes them different from the Company in any material aspect. Mr. Watkins' suggestions to the contrary severely calls into question the character and quality of his opinions in general.

Moreover, increasing the customer charge will not violate the principal of gradualism, as Mr. Watkins suggests.[520] While the increase in the residential customer charge viewed in total isolation is an increase over the current charge, the high percentage increase is purely reflective of the extremely low amount of the current customer charge. Likewise, increasing the customer charge as proposed by the Company will be revenue neutral to the residential class.[521] A higher customer charge will result in less of the rate increase being included in the volumetric energy

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[516] *See id.*, pp. 28-30.

[517] *See* HVR 1:52:40 (Mar. 8, 2018); Company Hearing Exhibit 7, p. 1.

[518] *See* Company Hearing Exhibit 7.

[519] *See id.*; HVR 1:52:25 (Mar. 7, 2018).

[520] *See* Watkins Direct, p. 27.

[521] *See* Company Response to Staff DR-02-062; HVR 2:10:20 (Mar. 8, 2018).

charge. Likewise, there is no inequity arising from increasing the customer charge. According to the Company's analysis, the impact of the increase in the customer charge will have no discernable relative impact (0.8%) on low-income customers.[522] The proposed customer charges are reasonable and should be approved.

b. Reduction in Interclass Rate Subsidies

In order to adhere to the principle of cost causation, the Company's proposed rates work towards reducing interclass subsidies. This objective results in the Company proposing increases to rate schedules RS, DS, DT, EH, SP and DP to better align charges with cost causation.[523] Although Mr. Bieber suggested that the Company could be more aggressive in reducing the subsidies,[524] he provided no analytical basis or other tangible evidence to support what amounts to a self-serving claim. The Commission should ignore Mr. Bieber's recommendation.

c. The Company's Proposed Amendments to Rate TT are Reasonable

The Company is proposing to alter the structure of Rate TT to include a summer and winter on-peak energy rate similar to the structure of Rate DT.[525] The change will be revenue neutral to the class and send an appropriate price signal that promotes off-peak usage.[526] No intervenor has challenged the change, which should be approved.

C. The Company's Proposed New Riders are Reasonable

Duke Energy Kentucky is also proposing three new tariff riders in this proceeding. Rider FTR is a reconciliation mechanism for FERC-jurisdictional transmission expenses.[527] Rider ESM

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[522] *See* Sailers Direct, pp. 11-12.

[523] *See id.*, p. 9.

[524] *See* Bieber Direct, pp. 4, 8-11.

[525] *See* Sailers Direct, p. 12.

[526] *See id.*; Company Response to KIUC DR-01-001.

[527] *See* Application, ¶ 37.

will implement the Company's new environmental surcharge mechanism and provide cost recovery for the Company's proposed Environmental Compliance Plan (ECP).[528] Rider DCI will allow the Company to make timely recovery of investments in its distribution system to proactively assure reliability and robustness throughout the service territory.[529] As explained below, each of these proposed riders is reasonable and should be approved.

1. The Company's Proposed Rider FTR is Reasonable

Duke Energy Kentucky is a transmission dependent utility, having little investment in actual transmission assets.[530] The Company relies upon the bulk transmission system of its parent company, Duke Energy Ohio, and that of neighboring utilities in PJM. Transmission is thus a significant expense for the Company.[531] The vast majority of the transmission costs that Duke Energy Kentucky incurs are all subject to tariffs approved by FERC.[532]

a. Rider FTR is Needed to Address Volatile Expenses Arising from FERC-Approved Rates

The purpose of Rider FTR is to create a reconciliation mechanism for the Company's FERC-regulated transmission costs. These transmission costs include, but are not limited to: Network Integration Transmission Service (NITS); firm and non-firm point-to-point transmission charges; and market administration fees, all established under PJM's Open Access Transmission Tariff (OATT) approved by FERC.[533] In addition, the Company is proposing that Rider FTR also track incremental changes in costs associated with PJM's Regional Transmission Expansion Plan (RTEP) costs that are incremental, higher or lower, to what the Company is proposing to include

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[528] *See id.*, ¶ 28.

[529] *See id.*, ¶ 25.

[530] *See id.*, ¶ 37.

[531] *See id.*, ¶ 38.

[532] *See* John D. Swez Direct Testimony (Swez Direct), p. 29 (filed Sep. 1, 2017).

[533] *See* Application, ¶ 37; Wathen Direct, p. 18.

in its base rates.[534] Because both MISO and PJM began charging transmission expansion costs after the completion of the Company's last rate case, customers have not been charged for these costs at all.[535] The Company has virtually no control over these charges as they are assessed pursuant to FERC-approved tariffs.[536] These costs are highly volatile and vary month-to-month and year-to-year.[537] The Company is not seeking recovery in base rates or in any rider, for any transmission expansion planning costs related to the Midcontinent Independent System Operator, Inc. (MISO), also known as MTEP charges.

Incremental costs will be recovered through a dollar per kWh charge/credit to customers.[538] This will insure that the Company is recovering no more and no less than the actual transmission costs necessary to serve its Kentucky customers.[539] Moreover, Rider FTR will also ensure that the Company remains earnings neutral and customers will not be over- or under-paying as a result of any cost increases or decreases in bulk transmission expenses.[540] In particular, the Company is proposing a mechanism that will operate much like Rider FAC and the Company's Accelerated Service Replacement Program (Rider ASRP), for its gas business, in that it will make regular filings subject to periodic review by the Commission.[541] The Company is proposing to establish a level of these costs to be reflected in base rates that will be incrementally tracked with periodic quarterly filings with actual cost information to be reconciled.[542] The Company is proposing a

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[534] *See id.*, p. 18.
[535] *See id.*, p. 21.
[536] *See* Swez Direct, p. 27.
[537] *See id.*
[538] *See* Sailers Direct, p. 14.
[539] *See* Application, ¶ 38; Swez Direct, p. 27.
[540] *See* Application, ¶ 39.
[541] *See id.*, ¶ 40; Wathen Direct, p. 19.
[542] *See* Application, ¶ 40.

comprehensive annual review by the Commission with a process similar to that of Rider ASRP, wherein the Company will make an annual application for new rates for Rider FTR to be reviewed for determination of reasonableness and accuracy.[543] This will allow the Company to recover or refund the incremental costs (above and below) what is reflected in base rates.[544] Costs recovered under Rider FTR will be allocated to the various rate classes based upon each rate class' respective share of total kWh sales and charged on a per kWh basis.[545]

b. The Intervenors' Objections to Rider FTR are Unfounded and Unpersuasive

i. The AG's Objections

Mr. Kollen, on behalf of the Attorney General, objects to the creation of Rider FTR on the alleged basis that it would: (1) mitigate the Company's incentive to use its influence to keep expenses allowed under Rider FTR as low as possible;[546] (2) shift cost recovery from base rates to a rider;[547] (3) result in "unending" quarterly updates to rates;[548] (4) allow the Company to increase rates even if it is earning above its authorized return;[549] and (5) be inconsistent with the Commission's rejection of a similar proposal from Kentucky Power Company in Case No. 2014-00396.[550] Though numerous, none of these objections – viewed in isolation or in combination – has merit.

Mr. Kollen's suggestion that Rider FTR will somehow create a disincentive to managing costs is a red-herring. Carried to its illogical extreme, Mr. Kollen's suggestion would cause the

543 *See id.*, ¶ 40.

544 *See* Swez Direct, p. 28 (listing the PJM billing codes that would apply to Rider FTR).

545 *See* Company Response to NKU DR-01-008.

546 *See* Kollen Direct, p. 62.

547 *id.*

548 *See id.*

549 *See id.*

550 *See id.*, pp. 62-63.

Commission to repeal its FAC regulation on the notion that Rider FAC incentivizes a utility to overpay for coal.[551] The idea is silly on its face. In this context, the expenses in question are those which arise from Duke Energy Kentucky's participation in PJM pursuant to rates that are approved by FERC.[552] They are highly volatile in nature.[553] The Company participates as a stakeholder in PJM matters and appears before FERC when necessary, but it has very little direct influence on either PJM or FERC. For that matter, the AG himself also regularly participates as a stakeholder at PJM and has not been shy about filing comments with FERC.[554] The issues coming before PJM and FERC are likely to impact all electric utilities, not just the Company. The existence or absence of Rider FTR will have no discernable impact on the Company's interactions with PJM or FERC. The Company will still have every incentive to minimize its FERC jurisdictional costs when Rider FTR is approved.[555]

Moreover, the use of discrete riders and cost trackers is a well-known and utilized practice in Kentucky. Indeed, the Kentucky Supreme Court has expressly affirmed the Commission's authority to approve riders even in the absence of a specific statutory authorization to do so.[556] Even an ostrich with its head in the sand would be more informed as to the great number of riders in effect across the tariffs of virtually every utility regulated by the Commission. Mr. Kollen's concern as to cost-shifting is ridiculous. Likewise, his concern that Rider FTR would lead to

551 *See* Wathen Rebuttal, p. 35.

552 *See* Swez Direct, p. 26.

553 *See id.*

554 *See e.g.* PJM Markets and Reliability Committee Meeting Minutes (PJM MRC, Jan. 25, 2018). (*http://www.pjm.com/~/media/committees-groups/committees/mc/20180220-webinar/20180220-item-07a-draft-minutes-mrc-20180125.ashx*); *In the Matter of Kentucky Power Company*, Order on Tariff Filings Docket Nos. ER13-230-000 (Fed. Eng. Reg. Comm'n, Dec. 23, 2013) (*https://www.ferc.gov/CalendarFiles/20131223164236-ER13-238-000.pdf*).

555 *See* Wathen Rebuttal, p. 16.

556 *See Kentucky Public Service Commission v. Commonwealth of Kentucky, ex. rel. Jack Conway and Duke Energy Kentucky, Inc.*, 324 S.W. 3d 373 (Ky. Oct. 21. 2010).

endless quarterly updates is also inconsequential. Most riders are updated on a monthly, quarterly or annual basis – and the frequency of a rider being updated is no basis for rejecting the reasonableness of the rider.[557]

Mr. Kollen's concern that Rider FTR will somehow allow the Company to exceed its authorized return is equally unpersuasive. A rider tracks both the costs and the credits associated with a category of expense. The illogical nature of Mr. Kollen's suggestion surfaces in this argument as well. Rider FTR will operate similar to the Company's Rider FAC and, if approved, Rider ESM.[558] Both of those riders allow the Company to recover discrete costs without regard to the Company's overall earnings.[559] But in so doing, the existence of riders also prevent the Company from over-earning for any expenses that may have been over-estimated in the test year and therefore would be over collected in base rates if the riders did not exist. A tracker is a reasonable regulatory tool to accommodate the volatility of a discrete utility expenses and its use in this context is entirely appropriate.

Mr. Kollen's final argument presents another example of selective memory. While he correctly states that the Commission chose not to authorize a rider for Kentucky Power Company to recover PJM related expense in Case No. 2014-00396, he conveniently forgets that such a rider was pending, and subsequently authorized, in Kentucky Power Company's most recent base rate case.[560] Mr. Kollen's arguments are illogical, disingenuous, inconsistent with the state of Kentucky regulatory practice and non-credible. As such, they should be rejected.

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557 *See* Wathen Rebuttal, p. 34.

558 *See id.*, p. 36.

559 *See id.*

560 *See In the Matter of: Electronic Application of Kentucky Power Company for (1) A General Adjustment of its Rates for Electric Service: (2) An Order Approving its 2017 Environmental Compliance Plan: (3) An Order Approving its Tariffs and Riders; (4) An Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities: and (5) An Order Granting all Other Required Approvals and Relief*, Order, Case No. 2017-00179 (Ky. P.S.C. Jan. 18, 2018). At the time Mr. Kollen's testimony was filed, the Commission had not yet approved the tariff, although it was

ii. NKU's Objections

NKU's witness, Mr. Collins, opposes Rider FTR. Mr. Collins asserts that the "criteria needed for establishment of a rider are that the cost elements subject to the regulatory mechanism meet the following: (1) must be outside the utility's control; (2) must be volatile and unpredictable; and (3) must be large enough to significantly affect the utility's ability to earn its authorized return."[561] His primary concern is that the expenses covered by Rider FTR do not appear to be volatile.[562] What is quickly apparent is that Rider FTR easily satisfies each of these criteria. The costs imposed upon Duke Energy Kentucky by tariffs approved by FERC are, by definition, costs that are beyond the control of the Company. Moreover, the Commission has already determined in the context of Kentucky Power Company's operations that these costs are volatile in nature.[563] Duke Energy Kentucky is obligated for its load ratio share of these same volatile costs, pursuant to the same FERC-approved tariffs as Kentucky Power. Finally, Duke Energy Kentucky's return on equity can be reduced by 20 basis points by as little as $1 million in incremental costs.[564] Mr. Collins' own standard is satisfied. Rider FTR is a reasonable ratemaking solution to solve a problem arising from the volatility of expenses incurred via FERC-approved tariffs. The intervenors' objections are unavailing and should be given no weight. Rider FTR should be approved as proposed.

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part of the Settlement Agreement that was pending before the Commission. Mr. Kollen argued at the hearing that the Kentucky Power Case was different based upon certain unidentified facts.

[561] Collins Direct, p. 9.

[562] *See id.*, p. 15.

[563] *See* Wathen Rebuttal, p. 37, *citing In the Matter of: Electronic Application of Kentucky Power Company for (1) A General Adjustment of its Rates for Electric Service; (2) An Order Approving its 2017 Environmental Compliance Plan; (3) An Order Approving its Tariffs and Riders; (4) An Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities; and (5) An Order Granting all Other Required Approvals and Relief*, Order, Case No. 2017-00179, p. 53 (Ky. P.S.C. Jan. 18, 2018).

[564] *See* Wathen Rebuttal, p. 37.

2. The Company's Proposed Rider ESM is Reasonable

As part of its Application, Duke Energy Kentucky is also seeking Commission authority to establish a Rider ESM, pursuant to KRS 278.183 and other applicable law, to recover the costs of its compliance with various environmental regulations at East Bend.[565] An updated tariff was provided along with the rebuttal testimony of Company witness, Ms. Lawler.[566] The Company has already gained Commission approval for each of the projects to be initially included in its accompanying Environmental Compliance Plan (ECP).[567]

a. Summary of Applicable Kentucky Law

KRS 278.183, the environmental surcharge statute, was enacted "to promote the use of high sulfur Kentucky coal by permitting utilities to surcharge their customers for the cost of a scrubber which is part of a power plant that cleans high sulfur coal in order to meet the acid rain provisions of the Federal Clean Air Act amendments of 1990."[568] Section 1 of the statute contains the guarantee of cost recovery for such environmental compliance costs:

> Notwithstanding any other provision of this chapter, effective January 1, 1993, 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 which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal in accordance with the utility's compliance plan as designated in subsection (2) of this section. These costs shall include a reasonable return on construction and other capital expenditures and reasonable operating expenses for any plant, equipment, property, facility, or other action to be used to comply with applicable environmental requirements set forth in this section. Operating expenses include all costs of operating and maintaining environmental facilities, income

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[565] *See* Application, ¶ 28. The Company tendered its Notice of Intent on August 2, 2017, in accordance with KRS 278.183(2).

[566] *See* Lawler Rebuttal, Attachment SEL-Rebuttal-1(a), (b).

[567] The Company's initial ECP is filed as Attachment JAM-1 to the Direct Testimony of Mr. Joseph A. Miller, Jr. (filed Sep. 1, 2017).

[568] *Kentucky Indus. Utility Customers, Inc. v. Kentucky Utilities Co.*, 983 S.W.2d 493, 496 (Ky. 1998).

> taxes, property taxes, other applicable taxes, and depreciation expenses as these expenses relate to compliance with the environmental requirements set forth in this section.[569]

In order to obtain rate relief under the environmental surcharge statute, a utility must "submit to the commission a plan, including any application required by KRS 278.020(1), for complying with the applicable environmental requirements set forth in [KRS 278.183(1)]." Following that:

> ...[T]he commission shall conduct a hearing to: (a) Consider and approve the plan and rate surcharge if the commission finds the plan and rate surcharge reasonable and cost-effective for compliance with the applicable environmental requirements set forth in subsection (1) of this section; (b) Establish a reasonable return on compliance-related capital expenditures; and (c) Approve the application of the surcharge.[570]

The Kentucky Supreme Court characterized KRS 278.183 as "a new right" that "did not exist before the enactment of the surcharge."[571] Thus, the Kentucky General Assembly has chosen to encourage the use of coal by enacting a surcharge mechanism that guarantees a utility the ability to recover costs associated with compliance with environmental mandates. The Commission has commented upon the prescriptive nature of the KRS 278.183 by observing that it "must consider the plan and the proposed rate surcharge, and approve them if [the Commission] finds the plan and rate surcharge to be reasonable and cost effective."[572]

b. Summary of Applicable Environmental Authorities

In April 2009, the EPA began assessing the integrity of ash dikes nationwide and began developing regulations to manage CCRs. CCRs primarily include fly ash, bottom ash, and FGD

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[569] KRS 278.183(1).

[570] KRS 278.183(2).

[571] *Kentucky Indus. Utility Customers, Inc.*, at 500.

[572] *In re the Application of Big Rivers Electric Corporation for Approval of its 2012 Environmental Compliance Plan*, Order, Case No. 2012-00063, p. 16 (Ky. P.S.C. Oct. 1, 2012).

byproducts (typically calcium sulfate (gypsum) or calcium sulfite) that are destined for disposal.[573] In June 2010, the EPA proposed a rule containing two options for handling CCRs: 1) as a special waste listed under the Resource Conservation and Recovery Act (RCRA) Subtitle C Hazardous Waste Regulations; and 2) as a solid waste under RCRA Subtitle D Non-Hazardous Waste Regulations.[574] Both options included dam safety requirements and had strict new requirements regarding the handling, disposal, and beneficial use of CCRs except when reused in encapsulated applications (such as ready-mix concrete and the production of wallboard).[575]

When the EPA published its proposed ELG Final Rule revisions, it indicated that it was working to integrate the ELG Final Rule with the CCR Final Rule. In the CCR proposal, the EPA said there could be strong support for a conclusion that regulation of CCR disposal under RCRA Subtitle D would be adequate because of 1) potentially lower CCR risk assessment results, 2) the ELG Final Rule requirements that the EPA may promulgate, and 3) increased federal oversight such requirements could achieve.[576] The CCR Final Rule and/or ELG Final Rule result in conversions to dry handling of fly ash and bottom ash; increased use of landfills; the closure of existing wet ash storage ponds; and the addition of alternative wastewater treatment systems.[577] In its ELG Final Rule proposal, the EPA indicated that the requirements of the two rules needed to be harmonized before either rule was released. The CCR Final rule was published as final as a Subtitle D, non-hazardous waste rule on April 17, 2015.[578]

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[573] *See* Tammy Jett Direct Testimony (Jett Direct), p. 11 (filed Sep. 1, 2017).

[574] *See id.*, pp. 11-12.

[575] *See id.*, p. 12.

[576] *See id.*

[577] *See id.*

[578] *See id.*

The ELG Final Rule was published on November 3, 2015. This rule sets new or additional requirements for wastewater streams from several processes and byproducts at steam electric generating plants. Some of these wastewater streams are generated at East Bend, including but not limited to, fly ash and bottom ash wastewaters. This rule will require the Company to take action to achieve compliance that includes conversion of the existing wet ash system to a dry ash handling system.[579] As part of converting to dry ash handling, new wastewater treatment systems must be installed and the existing pond can no longer be used in its current form as an ash transport water treatment system.[580] Additionally, due to East Bend site limitations (*e.g.*, proximity to the river, availability of other land, etc.) the existing pond must be repurposed through clean closure to comply with the ELG Final Rule.[581]

Compliance deadlines with some aspects of the CCR Final Rule began within 6-12 months after publication, while other actions will require 5 years or more.[582] Compliance with the ELG Final Rule was set to begin as early as November 1, 2018, but no later than December 31, 2023. On August 14, 2017, the EPA filed a motion with the United States 5th Circuit Court of Appeals to put portions of the 2015 ELG Final Rule litigation on hold while it reconsiders certain ELG Final Rule limits.[583] The EPA is requesting to sever and hold in abeyance the issues related to bottom ash transport water, FGD wastewater, and IGCC gasification wastewater.[584] The EPA is also requesting to propose reconsideration of the effluent limits and pre-treatment standards for only bottom ash transport water and FGD wastewater.[585] This action alone does not have a direct

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[579] *See id.*, pp. 12-13.

[580] *See id.*, p. 13.

[581] *See id.*

[582] *See id.*

[583] *See id.*

[584] *See id.*

[585] *See id.*

impact on any compliance needs or implementation schedules for East Bend projects because the drivers for the station's ash-related projects were not limited to the ELG Final Rule.[586] However, the action provides an indication that the EPA will review and potentially change the ELG Final Rule limits for the two waste streams.[587] Duke Energy Kentucky expects the EPA will move quickly to finalize this rule once the court rules on the recent motion for reconsideration, however, the reconsideration process could take between a year and 18 months to complete. As expected, the combination of ELG Final Rule, CCR Final Rule, and Kentucky groundwater regulations implementation require East Bend's conversion to dry ash handling (bottom ash).

c. Overview of Projects Proposed to be Included in the ECP

The Company's initial ECP will be composed of projects that have already been approved by the Commission. In particular, the four projects pertain to the amortization of the Company's East Bend ash pond closure/retirement obligation (ARO) accounting treatment as approved in Case No. 2015-00187,[588] and its process water system and redirection and pond repurposing strategy recently approved in Case No. 2016-00398.[589] The Company also proposes to prospectively recover environmental reagent expenses and the consumable inventories for the native portion of emission allowances used and consumed at East Bend to meet environmental operational requirements and constraints.[590] The Company also proposes to credit back customers any proceeds from emission allowance sales.

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[586] *See id.*

[587] *See id.*

[588] *See In the Matter of the Application of Duke Energy Kentucky, Inc., for an Order Approving the Establishment of a Regulatory Asset for the Liabilities Associated with Ash Pond Asset Retirement Obligations*, Order, Case No 2015-00187 (Ky. P.S.C. Dec. 15, 2015).

[589] *See In the Matter of the Electronic Application of Duke Energy Kentucky, Inc., for a Certificate of Public Convenience and Necessity Authorizing the Company to Close the East Bend Generating Station Coal Ash Impoundment and for All Other Required Approvals and Relief*, Order, Case No. 2016-00398 (Ky. P.S.C. June 6, 2017).

[590] *See* Application, ¶ 33; Wathen Direct, p. 32; Miller Direct, p. 21; Company Response to Staff DR-03-003.

The fully loaded total estimated cost of pond closure (bottom ash removal and dewatering) is approximately $29,000,000.[591] The estimated fully loaded cost of construction (internal and external labor included) for pond repurposing to a lined retention pond for ELG compliance is approximately $42,000,000.[592] The total estimated fully loaded cost of construction for water redirection (internal and external labor included) is approximately $22,000,000.[593]

The Company is proposing to track these costs through Rider ESM to ensure that customers only pay for the actual costs incurred. None of the capital projects identified for inclusion in the Company's initial ECP are currently included in the Company's base electric rates and have been excluded from the forecasted test period in this proceeding.[594] As such, the capital, property tax, depreciation and ongoing O&M expenses have not been included as part of the test period.[595] Because the Company has already been granted the requisite Certificates of Public Convenience and Necessity (CPCNs) for each of these projects, the Commission should approve the proposed ECP.

d. Coal Ash ARO Amortization Period

The Company seeks to recover the amounts associated with the ash pond ARO that have been spent to date as well as all future costs associated with the Company's ECP. In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification for Asset Retirement and Environmental Obligations (ASC 410-20) and FERC's Order No. 631, Duke Energy Kentucky records an ARO when it has a legal obligation to incur retirement costs associated with the retirement of a long-lived asset and the obligation can be reasonably

[591] *See* Miller Direct, p. 20.

[592] *See id.*

[593] *See id.*

[594] *See* Application, ¶ 34.

[595] *See id.*

estimated.[596] The ARO Duke Energy Kentucky has recorded resulting from this CCR Final Rule uses costs based on management's best estimates of required underlying activities and at fair value, as required under Generally Accepted Accounting Principles (GAAP) under ASC 410-20.[597] Actual costs incurred through December 31, 2017 total $15.7 million.[598] The remaining balance (as detailed in CSL-Rebuttal-1 Attachment) of $13.3 million represents projections, which are subject to change. The annual amortization expense of the total ARO related to costs associated with the closure of the East Bend ash pond is $3,951,879.[599] The ARO liability is calculated based on the estimated cash outflows and is reduced as actual spend occurs related to expected ARO closure activities.[600] The Company proposes to levelize the full amount of the ARO (amounts spent through March 31, 2018 and remaining amounts estimated to be spent) subject to adjustments for COR credit and carrying costs on the unrecovered coal ash spend regulatory asset,[601] in order to minimize the rate impact to customers.[602] The Company also proposes to amortize the levelized ARO expenditures over a ten-year period, starting on June 1, 2018 when the Company would make its first Rider ESM filing.[603] The true-up of actual versus projected ARO expenditures would occur via Rider ESM. As demonstrated on CSL-Rebuttal-1, under this recovery method, the total cost recovery at any point in time will never be greater than actual costs incurred.

[596] *See* Lee Direct, p. 11.

[597] *See id.*

[598] *See* Cynthia Lee Rebuttal Testimony (Lee Rebuttal), pp. 2-3 (filed Feb. 14, 2018).

[599] *See id.*, Attachment CSL-Rebuttal.

[600] *See* Lee Direct, p. 11.

[601] Per the Commission's Order in Case No. 2015-00187, the ARO accrues carrying costs at the Company's annual weighted cost of capital (WACC). *See* Company Response to Staff DR-02-035.

[602] *See* Lee Direct, p. 12. If the ARO was recovered during the active period of ash pond closure, the recovery of costs would be accelerated so that the entirety of the ARO would be recovered by 2021. *See* Company Response to Staff DR-02-033.

[603] *See* Lee Direct, pp. 12-13; Wathen Direct, p. 35.

The Company also provided the annual revenue requirement and total collections if the ARO is recovered over a ten-year or 23 ½-year period.[604] If the regulatory asset is amortized over a 23 ½-year period, consumers will ultimately pay a higher price (approximately $18.3 million) over the life of the recovery because the regulatory asset would continue to accrue a carrying charge for an additional 13 ½-years, which is unnecessary.[605] There is no nexus between the remaining life of East Bend and the amortization period for recovery of the ARO expenditures; so there is no basis for amortizing recovery of a longer period of time. The ARO expenditures represent costs incurred to close the basin which is currently estimated to be completed by 2021. The Commission should accept the Company's proposed levelization of the entire ARO over a ten-year period. This is in the best interest of customers and the Company.

Based upon the foregoing, the Company's Rider ESM should be approved, the Company's ECP should be accepted based upon the CPCNs already obtained, the ash pond ARO should be amortized as requested and all future, non-ARO environmental costs included within the Company's ECP should be recovered as incurred as set forth in the updated proposed tariff.

3. The Company's Proposed Rider DCI is Reasonable

a. Summary of Applicable Kentucky Law

The Commission first approved an infrastructure development rider in the Company's 2001 natural gas rate case.[606] That rider encouraged the improvement of Duke Energy Kentucky's natural gas system by increasing safety and improving reliability. A legal challenge from the AG was unsuccessful as the Kentucky Supreme Court affirmed the Commission's Order and

[604] *See* Company Response to Staff Post-Hearing DR-01-001.

[605] *See id.*

[606] *See In the Matter of the Application of the Adjustment of Gas Rates of the Union Light, Heat and Power Company*, Order, Case No. 2001-00092 (Ky. P.S.C. Jan. 31, 2002).

recognized the significance of KRS 278.509, a subsequently enacted statute that codified the Commission's prior Order.[607] The Commission later approved a second infrastructure development rider for service line replacements.[608] Both programs have been highly successful.

In light of the foregoing authorities and Duke Energy Kentucky's successful AMRP and ASRP programs, the Company is proposing to implement a distribution system reliability and integrity improvement plan that will be comprised of specific new and Commission-approved initiatives designed to enhance the safety and reliability of the Company's electric delivery system.[609] The costs for this program will be recovered through a separate recovery mechanism, Rider DCI, that will be adjusted and subject to annual true-up following Commission review and approval.[610] Rider DCI will include incremental capital investment (not O&M expense), depreciation, taxes, and a reasonable return that is incremental to base rates.[611] As part of this annual application, the Company may propose new reliability or integrity programs for Commission consideration and approval for implementation as part of the Company's distribution integrity and reliability plan.[612] The rate of return established for the rider will be the overall pre-tax rate of return, approved by the Commission in this current case.[613] The revenue requirement for the rider will be rolled into base rates when new base rates are established as a result of a future

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[607] *See Kentucky Public Service Comm'n v. Commonwealth of Kentucky, ex. rel. Jack Conway and Duke Energy Kentucky, Inc.*, 324 S.W. 3d 373 (Ky. Oct. 21, 2010).

[608] *See In the Matter of the Application of Duke Energy Kentucky, Inc., for a Certificate of Public Convenience and Necessity Authorizing the Implementation of an Accelerated Service Line Replacement Program, Approval of Ownership of Service Lines, and a Gas Pipeline Replacement Surcharge*, Order, Case No 2015-00210, (Ky. P.S.C. Feb. 2, 2016).

[609] *See* Application, ¶ 25.

[610] *See* Sailers Direct, p. 15.

[611] *See* Application, ¶ 25; Wathen Direct, p. 27; Anthony "Tony" Platz Rebuttal Testimony (Platz Rebuttal), p. 7 (filed Feb. 14, 2018).

[612] *See* Application, ¶ 25.

[613] *See* Wathen Direct, p. 28.

base rate case filing; however, the Company commits that if it has not had another electric base rate proceeding within three years of the implementation of the rider, it will submit testimony supporting the continuation of the approved rate of return or propose a new rate of return for the Commission to consider for the rider.[614]

b. Overview of Investments to be Included in Rider DCI (Targeted Underground)

Most of Duke Energy Kentucky's customers are currently served via overhead transmission and distribution lines; however, the Company is increasingly serving customers with underground facilities.[615] This shift is attributable in part to the results of the Company's Fastrack surveys which show the Company's lowest satisfaction level (74%) for residential customers is centered on outage/restoration experiences.[616] Today, the Company considers several performance factors when determining where system modifications are needed. Examples of these factors include: customer load growth, economic development area construction, equipment loading capabilities, system efficiency, power quality, reliability factors (SAIDI, SAIFI), and system protection factors.[617] Utilizing these factors, in conjunction with a system planning software tool, allows a detailed system analysis of the Duke Energy Kentucky electrical distribution system. Based on analysis, construction projects are then developed to enhance available system supply, improve system public safety, and improve performance deficiencies.[618] Construction project options are reviewed with other stakeholders to ensure a balanced, efficient, and workable plan has been developed. Approval to implement the project is the responsibility of

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[614] *See id.*

[615] *See* Henning Direct, p. 4.

[616] *See id.*, p. 15.

[617] *See* Company Response to Staff DR-01-012.

[618] *See id.*

management based on the effectiveness and total cost of the project.[619] It is this process that led the Company to pursue the Rider DCI.

With Rider DCI in place, the Company is proposing a single program, Targeted Underground, to be included in the initial rider filing. This program will improve the customer's electricity experience by relocating "at risk" overhead circuits to underground service in a concentrated effort to improve that circuit's integrity and overall reliability.[620] The Targeted Underground program will identify specific areas of its distribution system that experience higher than acceptable frequency of outages and replace overhead wires with underground cables in an effort to harden the system, thereby increasing overall reliability.[621] Within this program, Duke Energy Kentucky is also proposing to take over the ownership of underground service lines that are replaced either as part of the Targeted Underground program or existing customer-owned underground service lines that experience a failure and are replaced by Duke Energy Kentucky.[622] Based upon the Company's analysis, the Targeted Underground program will significantly improve the Company's reliability in relation to major storm impacts.[623] In addition, the program is expected to achieve a 16% reduction in outage events and a 15-20% reduction in major event day duration depending on the severity of the event.[624]

c. The Intervenors' Objections to Rider DCI are Unpersuasive

The AG, NKU and Kroger all presented testimony in opposition to Rider DCI, however, none of these witnesses specifically challenged the costs or benefits associated with the Targeted

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[619] *See id.*

[620] *See* Application, ¶ 26.

[621] *See id.*

[622] *See id.*

[623] *See* Company Response to AG DR-01-089(a)(3).

[624] *See* Platz Rebuttal, p. 7.

Underground program. The arguments against the proposed tariff generally fall into three policy categories: (1) concerns regarding single-issue ratemaking;[625] (2) the perception of reduced incentives to manage costs;[626] and (3) a preference for addressing such issues in base rate cases.[627] Again, each of these arguments fails to demonstrate why Rider DCI should not be approved.

With regard to the question of whether Rider DCI represents improper single-issue ratemaking, the intervenors' witnesses all ignore the great number of similar riders that are in effect throughout the Commonwealth and around the nation.[628] Moreover, the Kentucky Supreme Court has expressly affirmed that an infrastructure investment rider such as Rider DCI is squarely within the scope of the Commission's jurisdiction to approve and administer.[629] Duke Energy Kentucky's own experience with the now-completed Rider AMRP program and the ongoing Rider ASRP program demonstrate that such tariffs are effective and valuable to customers and the Company alike.

Moreover, just as with Rider AMRP and Rider ASRP, the Company has proposed significant safeguards to assure that program costs are properly managed. The process for implementing Rider DCI will allow any interested party the same right to review and challenge the Company's recovery of investments in its service territory that would be afforded in any base rate proceeding. But, because the scope of a Rider DCI case would be significantly narrower, the

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[625] *See* Baudino Direct, p. 46; Collins Direct, p. 14; Bieber Direct, pp. 4, 12-13.

[626] *See* Baudino Direct, pp. 46-47; Collins Direct, p. 14; Bieber Direct, pp. 4, 13-14.

[627] *See* Baudino Direct, p. 46; Collins Direct, p. 14. Mr. Baudino suggests that the Commission may choose to approve Rider DCI on a pilot basis. Should the Commission accept his recommendation, the Company requests that it be allowed to continue the pilot through its next electric base rate case so that it may be able to obtain sufficient data to demonstrate the value of the tariff.

[628] *See* Wathen Direct, Confidential Attachment WDW-2.

[629] *See Kentucky Public Service Comm'n v. Com. ex. rel. Conway*, 324 S.W. 3d 373 (Ky. 2010); *Com., ex rel. Stumbo v. Kentucky Public Service Comm'n*, 243 S.W.3d 374, 382 (Ky. App. 2007) ("The argument that it would be better if the costs were recovered in a general rate case rather than through a surcharge is nothing more than a policy argument beyond the scope of our review.").

ability of all parties to give full scrutiny to the operation of the Company's rider would be protected.[630] The existence of a rider does not in any way impede the Commission in fulfilling its statutory mandate to assure that rates are fair, just and reasonable. Rider DCI is a proposal that will enhance the safety and reliability of the Company's electric delivery system and should be approved.

D. The Company's Proposed Amendments to Existing Tariffs are Reasonable

As part of its Application, Duke Energy Kentucky is also proposing several revisions, amendments and updates to its existing tariffs, including: (1) amending Rider PSM to account for changes in the capacity and energy markets; (2) authorizing a new voluntary customer solution to allow customers to pay a fixed bill each month; (3) approving a new LED Street Lighting Tariff; (4) updating the Company's cogeneration tariffs; (5) amending Rate TT to include a summer and winter on-peak energy charge; (6) updating its Service Regulations tariff; (7) eliminating tariffs that have previously been withdrawn, expired or are no longer in use; and (8) addressing AMI-related non-recurring charges.[631]

1. The Company's Proposed Amendments to Rider PSM are Reasonable

a. History of Rider PSM

Rider PSM was established by Commission Order entered in Case No. 2003-00252,[632] to provide a means for the Company to flow through to customers most of the profits (or margins) it derives from owning and operating its generation.[633] Beginning in January 2007, Duke Energy

[630] *See* Platz Rebuttal, p. 3.

[631] *See* Application, ¶ 41.

[632] *See In the Matter of: The Application of the Union Light, Heat and Power Company for a Certificate of Public Convenience to Acquire Certain Generation Resources and Related Property; For Approval of Certain Purchase Power Agreements; For Approval of Certain Accounting Treatment, and for Approval of Deviation from Requirements of KRS 278.2207 and 278.2213(6)*, Order, Case No. 2003-00252 (Ky. P.S.C. Dec. 5, 2003).

[633] *See* Wathen Direct, p. 12.

Kentucky's customers began paying rates that included the embedded cost of generation owned by Duke Energy Kentucky.[634] The rationale for this arrangement is that customers should benefit from any opportunity the Company has to derive value from this generation.[635] The sharing mechanism in Rider PSM gives customers most of the value of this generation while giving the Company a small share as an incentive to maximize this value.[636]

Rider PSM has evolved over the years. In the original iteration, all of the first one million dollars in actual annual margins from off-system sales were assigned to customers with the Company and customers sharing any remaining benefits and costs of Rider PSM on a 50/50 basis.[637] In Case No. 2008-00489, the Company applied and received approval to begin including the net revenue from the Company's participation in the newly created MISO Ancillary Services Market (ASM) in Rider PSM.[638] In Case No. 2010-00203, the Company agreed to increase the sharing percentages to favor customers on a 75/25 basis.[639] Net proceeds from capacity purchases and sales were added to Rider PSM when the Company acquired DP&L's 31% interest in East Bend in Case No. 2014-00201.[640] All of these modifications have made to balance the risks of

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634 *See id.*

635 *See id.*

636 *See id.*, pp. 12-13.

637 *See In the Matter of: Application of the Union Light, Heat and Power Company D/B/A Duke Energy Kentucky for an Adjustment of Electric Rates,* Order, Case No. 2006-00172 (Ky. P.S.C. Dec. 21, 2006).

638 *See In the Matter of the Application of Duke Energy Kentucky, Inc. to Modify Rider PSM Off-System Sales Profit Sharing Mechanism to Account for Changes in Off-System Sales Due to the Initiation of the Midwest Independent System Operator Ancillary Services Market,* Order, Case No 2008-00489 (Ky. P.S.C. Jan. 30, 2009).

639 *See In the Matter of the Application of Duke Energy Kentucky, Inc. for Approval to Transfer Functional Control of its Transmission Assets from The Midwest Independent Transmission System Operator to the PJM Interconnection Regional Transmission Organization and Request for Expedited Treatment,* Order, Case No. 2010-00203 (Ky. P.S.C. Jan. 25, 2011).

640 *See In the Matter of the Application of Duke Energy Kentucky for (1) A Certificate of Public Convenience and Necessity Authorizing the Acquisition of the Dayton Power & Light Company's 31% Interest in the East Bend Generating Station: Approval of Duke Energy Kentucky, Inc.'s Assumption of Certain Liabilities in Connection with the Acquisition (3) Deferral of Costs Incurred as Part of the Transaction; and (4) All Other Necessary Waivers, Approvals and Relief,* Order, Case No. 2014-00201 (Ky. P.S.C. Dec. 4, 2014).

costs to the Company and provide customers with a greater opportunity for benefits by way of additional opportunity for credits. In its current form, Rider PSM captures most of all of the net margins of all: (1) off-system sales; (2) sales of emissions allowances (EAs); (3) ASM sales; and (4) capacity purchases and sales.[641]

b. Overview of Proposed Changes to Rider PSM

In this case, the Company is proposing to restructure Rider PSM to expand the categories of revenues (net of costs) available for inclusion in Rider PSM and to streamline the administration and calculation of the tariff.[642] The Company will not change the process of updating Rider PSM quarterly.[643] At a very high level, the Company is proposing to expand the categories of eligible net proceeds to include any net sales (costs and credits) available through wholesale markets that are attributable to the Company's ownership and dedication of generating assets to serve its Kentucky customers.[644] These objectives will be accomplished through several changes to the tariff.

First, consistent with the proposed changes to its FAC as discussed below, the Company is proposing to make adjustments to reflect PJM billing line items (BLIs) that are related to credits and charges attributable to the off-system sales shared with customers under the Rider PSM.[645] A full listing of the PJM BLIs that correspond to the foregoing costs and credits was tendered as Attachment JDS-4 to the Direct Testimony of Company witness John D. Swez.[646] These adjustments will better align Rider PSM with the Company's operations in the PJM markets.

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641 *See* Verderame Direct, pp. 26-27. Customers receive 100% of the benefit of EA sales. *See* Wathen Direct, p. 13.

642 *See id.*, p. 14.

643 *See id.*, p. 17.

644 *See* Verderame Direct, p. 27.

645 *See* Wathen Direct. p. 14.

646 *See* Swez Direct. pp. 24-25.

Second, the Company is proposing to adjust the categories of eligible net proceeds (credits and charges) that can be flowed through Rider PSM to include reconciliation of all types of revenues (positive or negative) derived from the Company's ownership and dedication of generating assets to Kentucky customers. Specifically, Rider PSM will be expanded to include all wholesale energy, capacity, and ancillary services markets (net costs and credits) that are now available or may become available in PJM.[647] This will include net costs and revenues that are derived from the PJM's newly implemented capacity performance rules and for short-term (less than one year in duration) capacity purchases necessary to meet the Company's three-year FRR plan.[648] The Company is also proposing to include costs of any capacity payments made to co-generation facilities, including qualifying facilities,[649] under the terms of one of Duke Energy Kentucky's cogeneration tariffs.[650] The Company is also proposing to include any net proceeds from the sale of renewable energy certificate (RECs) derived from any Company-owned renewable generating resources, including the recently placed in service solar facilities, as well as for any renewable resources that Duke Energy Kentucky may own in the future to the extent that the revenue requirement for such renewable resources are being recovered in base rates.[651]

Third, the current Rider PSM includes a provision for gains on the sale of EAs. As noted above, the Company is proposing to implement an environmental surcharge mechanism (Rider ESM) and will begin addressing cost recovery and the sharing of any gains/losses on the sale of

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[647] *See* Wathen Direct, p. 14.

[648] *See id.*; *see also* Verderame Direct, pp. 17-23 (describing PJM's Capacity Performance rules and their impact upon Duke Energy Kentucky.

[649] *See* 807 KAR 5:054.

[650] *See* Wathen Direct, pp. 14-15.

[651] *See id.*, p. 15.

EAs in the proposed Rider ESM.[652] Thus, the margins on sales of EAs will be removed from Rider PSM.

Finally, the Company proposes to modify the sharing percentage between customer and shareholders from the 75/25 split described above such that customers will begin receiving 90 percent of the amounts flowing through Rider PSM and to eliminate the $1 million threshold in the sharing formula.[653] Rather than have a two-stage sharing mechanism for some of the Rider PSM components, applying the 90/10 sharing formula to all components for all amounts will streamline the process for administering the tariff.[654] This will clearly benefit the Company's customers.

c. The AG's Objections to the Rider PSM Amendments are Unsupported and Unreasonable

The AG's witness, Mr. Kollen, proposed to shift $3.826 million that is currently accounted for through Rider PSM to base rates and "reset" the rider to $0.[655] In making this recommendation, however, Mr. Kollen conceded that he had not included any of the other components of Rider PSM (other than power sales) in his recommendation.[656] To support his proposed adjustment, Mr. Kollen relied upon what he termed the Commission's historical practice to include off-system sales in base rates.[657] At the hearing, however, Mr. Kollen was forced to admit that neither KU nor LG&E currently have a component of off-system sales margins included in their base revenue requirement.[658] In fact, as part of each of their last two rate cases, the companies have excluded

[652] *See id.*

[653] *See id.*

[654] *See id.*

[655] *See* Kollen Direct. pp. 5, 9-10; AG Response to Staff DR-01-001.

[656] *See* HVR 3:18:57 (Mar. 8, 2018).

[657] *See* Kollen Direct, p. 9.

[658] *See* HVR 3:28:41 (Mar. 8, 2018).

100% of off-system sales margins from base rates.[659] Thus, at least three of the four investor-owned utilities operating in Kentucky do not include any portion of their off-system sales margins in base rates. This is a reasonable outcome. Moreover, Mr. Kollen was unable to cite any authority requiring a contrary result.[660] There is no compelling reason to complicate Rider PSM.[661] The Company believes it is a cleaner, simpler, and more transparent process, to exclude any Rider PSM revenues and costs from base rates. [662]

With regard to the proposed Company/customer split, Mr. Kollen developed a case of situational amnesia in this context as he first denied – and then had to concede – that he had personally advocated for a 90/10 split for the off-system sales tracker for KU and LG&E.[663] Likewise, he admitted that he was unaware that the AG had also previously advocated for a 90/10 split in Rider PSM charges and credits.[664] While he may disagree with it, Mr. Kollen could not affirm that the proposed 90/10 split is patently unreasonable.[665] The AG's recommendation to deny the amendments to Rider PSM, in whole or in part, should themselves be rejected.

d. Rider PSM Should be Approved as Amended

The Company's proposed changes to Rider PSM are reflective of the continuing developments in the regional energy and capacity markets. The changes in the revised tariff are reasonable, strike an appropriate balancing of interests between customers and the Company and will make it easier to administer Rider PSM.[666] Cost recovery through Rider PSM allows the

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[659] *See* Company Hearing Exhibit 10, p. 7 and Appendix A, p. 4; HVR 3:29:43 (Mar. 8, 2018).

[660] *See* HVR 3:34:08 (Mar. 8, 2018).

[661] *See* Lawler Rebuttal, p. 11.

[662] *See* Company Response to AG DR-01-046.

[663] *See* HVR 3:36:13 (Mar 8, 2018); Company Hearing Exhibit 9, p. 60.

[664] *See* HVR 3:39:29 (Mar. 8, 2018); Company Hearing Exhibit 11, pp. 18-19.

[665] *See* HVR 3:37:45 (Mar. 8, 2018).

[666] *See* Wathen Direct, pp. 15-16.

Company to meet its FRR capacity requirements through short-term (one-year in length or less duration) capacity products during the three-year planning horizon, more efficiently and more cost-effectively than through construction of new capacity resources or long-term contracting for generation.[667] This obviously benefits customers. Moreover, the Company's investment in East Bend and Woodsdale will help insulate the Company and customers from the risks of incurring any capacity performance assessments in PJM, while giving both constituencies the best opportunity to receive capacity performance rewards for reliability during emergency declaration periods.[668] The new Rider PSM also allows the Company to quickly and efficiently pass along the benefits of REC sales to its customers,[669] and mitigates the potential adverse impact of energy and capacity purchases from cogeneration facilities upon customers.[670] Updating the split between customers and the Company also simplifies the administration of the tariff and aligns the revenues and costs of ownership and dedication of the Company's generating assets, thereby assuring symmetry between costs and benefits of participation in the wholesale markets.[671] There is no reason to impose a more complex and less transparent process, which is what the AG's proposal would accomplish.[672] The amendments to Rider PSM should be approved as proposed.

2. The Company's Proposed Flexible Billing Programs are Reasonable

The Company is proposing to add two new flexible billing programs to its tariff.[673] The first such program is the Pick Your Own Due Date program. The Company's other proposal is to establish a Fixed Bill program. These programs are designed to provide Duke Energy Kentucky's

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[667] *See* Verderame Direct, p. 27.

[668] *See id.*

[669] *See id.*

[670] *See id.*, p. 30.

[671] *See id.*, p. 34.

[672] *See* Company Response to AG DR-01-046.

[673] *See* Alexander "Sasha" J. Weintraub, Ph.D. Direct Testimony (Weintraub Direct), p. 6 (filed Sep. 1, 2017).

customers, who desire to take a more active role in managing their energy usage, greater flexibility and control over their utility bill.[674] Both tariffs are voluntary programs that will be available, but not mandated, for customer participation. In addition, the Company is proposing to implement new additional services that will give customers greater control and transparency in their utility consumption and service through Usage Alerts and Outage Alerts. Of these four programs, only the Fixed Bill program will require a change to the Company's tariff.[675] Therefore, it is the only program which requires Commission approval herein.

a. Pick Your Own Due Date Bill Program

The Pick Your Own Due Date program will be available immediately to customers with AMI meters who do not elect to opt-out of the Company's Metering Upgrade.[676] Pick Your Own Due Date is an optional AMI-enabled program that allows customers to choose a monthly due date that best aligns with their personal situation.[677] Today, Duke Energy Kentucky's customers are assigned a billing cycle based upon Duke Energy Kentucky's ability to deploy and manage its meter reading personnel to attempt to manually read each and every mechanical meter on a monthly basis. The cycle is determined based upon geographical areas to more efficiently manage meter reading costs.[678] Once a customer is assigned a specific meter reading cycle, the cycle cannot be changed.[679] This results in the customer having no control over when their utility bill is due during the month. Pick Your Own Due Date will give customers greater flexibility, choice, and control by allowing them to shift their payment due date to a date that better aligns with their

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[674] *See id.*, p. 6.
[675] *See id.*, p. 12.
[676] *See id.*, p. 6.
[677] *See id.*
[678] *See id.*
[679] *See id.*, p. 7.

unique financial situation *(e.g.,* to coincide with paycheck dates, Social Security payments).[680] Customers will be able to decide which day of the month they prefer to pay their electricity bill without being penalized. There will be no noticeable changes to the customer's service other than a billing cycle alignment period that may mean one billing cycle month is longer or shorter than normal to sync up to the newly requested billing due date.[681]

b. Fixed Bill Program

Fixed Bill is a voluntary billing product for residential customers seeking certainty regarding their monthly electric bill. As the name suggests, Fixed Bill is a flat monthly billing charge for electric service that is guaranteed for twelve months.[682] Unlike the Company's current budget billing plan, the Fixed Bill customer will not be at risk for any true-up at the end of the twelve-month period.[683] Instead, the risk of weather and commodity volatility that is present in a conventional usage-based monthly utility bill is avoided by the customer through the payment of a small premium that is calculated as part of the flat monthly charge.[684] Experience in other jurisdictions has shown that a significant portion of the population of customers are willing to pay a small premium for the certainty that their electric utility bill will be predictable, equal and not subject to the risk of a true-up where the customer has the risk of owing a large sum at the end of some cycle.[685] Every twelve months, the Company will determine a new monthly charge to the customer should they choose to remain enrolled in the program. The Company will then factor any changes in usage patterns for the customer as part of that new monthly bill.[686] The availability of

[680] *See id.*

[681] *See id.*

[682] *See id.*

[683] *See id.*

[684] *See id.*

[685] *See id.*, pp. 7-8.

[686] *See id.*, p. 8.

the Fixed Bill product will not be dependent upon the metering upgrade technology and will be available upon Commission approval.[687]

The premium associated with the Fixed Bill program is designed to cover the program costs and variance-at-risk for participants.[688] The applicable risks include: weather risk, rate risk, asymmetrical customer risk and implementation risk.[689] The monthly amount is then calculated using the customer's actual usage as simulated through 30+ years of weather, and obtaining the 50th percentile for each month.[690] The expected price for the next twelve months is then applied to said usage calculation before being multiplied by the premium.[691] Fixed charges are not subject to the premium.[692] Moreover, the method by which the premium is calculated for a customer will be made available upon request.[693] While customers participating in the program will have the ability to terminate their participation prior to the end of the contract period, they will be subject to paying the balance due for actual usage at the time of termination.[694]

Fixed Bill has been very successful in Indiana, where approximately 60,000 customers have signed up for the program and customer retention is about 95%.[695] A Spring 2016 survey of Fixed Bill participants indicates that the customers are highly satisfied with this voluntary program.[696] Experience shows that Fixed Bill has no greater impact on energy efficiency and demand side management philosophies of customers than other budget billing programs currently

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687 *See id.*

688 *See* Company Response to Staff DR-03-005a.

689 *See id.*

690 *See* Company Response to Staff DR-03-005b.

691 *See id.*

692 *See id.*

693 *See* Company Response to AG DR-02-029d.

694 *See* Company Response to AG DR-02-029b.

695 *See* Weintraub Direct, p. 8.

696 *See id.*

available.[697] In Indiana, overall awareness of energy efficiency programs offered was the same and Fixed Bill participants had a higher participation rate in energy efficiency programs than non-participants.[698] For example, 16% of Fixed Bill customers participated in the Residential Energy Assessment Program (Home House Call), and only 11% of the non-participants took advantage of this valuable program offering a home audit.[699]

On behalf of the AG, Mr. Watkins suggests that the Fixed Bill program will result in "windfall profits" to the Company and that it provides a disincentive for customers to use energy wisely.[700] Both claims are mere hyperbole. Mr. Watkins apparently does not understand the proposed program, as the premium charged by the Company under its proposed Fixed Bill program is designed to cover the cost risk that the Company is taking on by guaranteeing a customer's bill regardless of energy usage for a period of time. For a given period, if customer usage is higher than the expected weather normal usage for a customer, the Company will bear the costs.[701] Moreover, the "premium" the Company receives through the Fixed Bill program serves as an offset to its revenue requirement, which has the practical effect of reducing an expense that would otherwise be charged to other customers. Given Mr. Watkins's unsubstantiated belief that customers on the proposed Fixed Bill will increase their energy consumption, it is difficult to understand his conflicting belief that the Company's proposed program will generate windfall profits for the Company. His opinion is illogical.

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[697] *See id.*, p. 9.

[698] *See id.*

[699] *See id.*

[700] *See* Watkins Direct, pp. 37, 39. Mr. Watkins also boldly claimed that it would be impossible for the Company to estimate a customer's future energy consumption but retracted the claim at the hearing. *Cf.* Watkins Direct, p. 39; HVR 2:18:50 (Mar. 8, 2018).

[701] If a customer's usage becomes excessive under the Fixed Bill program, the customer will see a corresponding rise in the following year of their participation in the program. This creates a long-term disincentive to abusing the program.

Moreover, there is no evidence to support his claim that the Fixed Bill program will actually result in higher energy usage. The program's implementation in Indiana suggests to the contrary – Fixed Bill customers are *more* energy conscious than non-participants.[702] Mr. Watkins' opinions regarding customer behavior turned out to be based purely on supposition rather than any tangible evidence.[703] And his cynical understanding of the customer psyche is definitely open to debate. Mr. Watkins has only spent six months in his thirty-seven year career actually working for a utility.[704] He has never worked as a customer service representative for a utility, nor served as a utility account manager.[705] He does not have a degree in psychology or any related field and he has never surveyed any of the Company's customers.[706] Mr. Watkins' opinion is not credible and should be ignored.

For the reasons set forth above, the completely voluntary Fixed Bill program is a reasonable solution to afford customers greater flexibility in purchasing energy. It gives residential customers certainty so that they can accurately budget for energy consumption without creating an incentive to over-consume. Moreover, the program has been wildly successful in Indiana,[707] and was recently approved in Florida. All of the real evidence in this case indicates that the Fixed Bill program is reasonable and should be approved. If, however, the Commission does not approve the Fixed Bill program, it would be necessary to increase the Company's revenue requirement by $122,230.[708] This would reverse the offset to the revenue requirement included in the Company's

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[702] *See* Weintraub Rebuttal, p. 6.

[703] *See* HVR 2:22:40 (Mar. 8, 2018).

[704] *See id.*, 2:21:57.

[705] *See id.*, 2:21:40.

[706] *See id.*, 2:22:05.

[707] The AG's witness, Mr. Watkins, conceded at the hearing that the Fixed Bill program in Indiana had not resulted in chaos in the energy markets. He was also unable to say if the program had resulted in a single complaint from customers or others. *See* HVR 2:25:14 (Mar. 8, 2018).

[708] *See* Weintraub Rebuttal, p. 8.

Application that was based upon the Company achieving a reasonable premium from the Fixed Bill program.[709] The Company's Fixed Bill program is an innovative customer solution that is purely voluntary, adds to customer satisfaction, and should be approved.

c. Usage Alerts and Outage Alerts

Usage Alerts is an AMI-enabled program that provides customers with a midcycle report of their usage to date, along with projections of the end-of-cycle bill, based on historical usage and weather data.[710] This functionality allows a customer to input their preferred threshold and receive notifications as they approach 75% and 100% of their preset threshold.[711] Customers can receive these messages via email and/or text message (SMS).[712] The Usage Alerts program will provide customers with greater transparency into their past and estimated future usage and will conveniently alert customers via email and text when they are approaching or have exceeded their pre-selected usage level for the month.[713] Customers enrolled in this program will be able to view the amount of electricity they have used so far during the current billing cycle, as well as the estimated cost of this usage.[714] This program can help customers avoid unexpected high bills.[715] Customers were able to subscribe to this service beginning in June 2017.[716] As of November 1, 2017, just over 10% of customers with certified AMI meters were participating in the program.[717]

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709 *See id.*

710 *See id.*, p. 10.

711 *See id.*

712 *See id.*

713 *See id.*

714 *See id.*

715 *See id.*

716 *See* Company Response to AG DR-01-081.

717 *See* Company Response to AG DR-02-039.

The Outage Alerts with AMI program will allow customers to receive enhanced proactive outage and restoration information regarding their service.[718] This program will allow the Company to provide even more timely and accurate information than what is currently available.[719] While Duke Energy Kentucky currently does have an outage message system in Kentucky, the information is at a very high system level and in many cases requires the customer to make the Company aware of their outage.[720] With the AMI-enabled capability, Duke Energy Kentucky will be able to communicate with enrolled customers proactively during outage events with more specific information regarding their service and making them more aware of the outage, the cause, and the estimated time of restoration.[721]

3. The Company's Proposed LED Street Lighting Tariff is Reasonable

The Company is also proposing a modest increase in the rates for existing street lighting rates, which is commensurate with the overall percentage increase allocated to street lighting customers.[722] In addition, the Company is proposing a street lighting tariff that would apply to light-emitting diode (LED) fixtures.[723] Rate LED is necessary to help the Company meet growing customer demand for LED street lighting.[724] No intervenor to the case has challenged the Company proposed Rate LED, which should be approved.

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[718] *See* Weintraub Direct, p. 11.

[719] *See id.*

[720] *See id.*

[721] *See id.*

[722] *See* Sailers Direct, p. 13.

[723] *See id.*

[724] *See id.*

4. The Company's Proposed Revisions to its Cogeneration Tariffs are Reasonable

Although the Company has not had any customers taking service under these tariffs to date. the Company continues to maintain both a Cogeneration and Small Power Production Sale and Purchase Tariff – 100 kW or Less schedule (QF Small Tariff) and a Cogeneration and Small Power Production Sale and Purchase Tariff – Greater Than 100 kW (QF Large Tariff) in compliance with the federal Public Utility Regulatory Practices Act (PURPA), FERC regulations implementing PURPA and 807 KAR 5:054, the Commission regulation applying PURPA to jurisdictional utilities.

The Company proposes to revise the QF Small tariff in two respects. First, it proposes to revise the energy purchase rate for all kWh delivered, using the two-year average of PJM's locational marginal price (LMP) at the Duke Energy Kentucky node as the proxy for the Company's avoided energy cost.[725] The revenues for these mandated energy purchases would then be recovered through the Company's Rider FAC as economy energy purchases.[726] Second, the Company proposes to add a Capacity Purchase Rate to the QF Small Tariff. Capacity payments under the proposed amended tariff will be based upon the avoided capacity cost in the then most recently completed IRP.[727] Taking into account the Company's status as an FRR entity within PJM, this amendment will also allow the Company to secure any necessary capacity from QF

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[725] *See id.*, p. 17.

[726] *See id.*

[727] *See id.* The Company's last IRP case was finished in 2015. *See In the Matter of: 2014 Integrated Resource Plan of Duke Energy Kentucky, Inc.*, Order, Case No. 2014-00273 (Ky. P.S.C. Aug. 19, 2015). The Company's next IRP filing is due to be filed later in June 2018.

Small Tariff producers.[728] The costs of any capacity purchases under the QF Small Tariff will flow through Rider PSM.[729]

The Company also proposes to revise the QF Large Tariff by adding a Capacity Purchase Rate. As with the QF Small Tariff, the payment for any capacity will be based upon the avoided capacity price as determined in the Company's then most-recent IRP case with costs recovered through Rider PSM.[730] The Company also proposes to maintain the Energy Purchase Rate at the PJM Real-Time LMP at the Duke Energy Kentucky node for all kWh delivered, with costs recovered through the Company's Rider FAC.[731]

These amendments to the cogeneration tariff are reasonable. They provide appropriate pricing structures for QF Small Tariff and QF Large Tariff producers without requiring Duke Energy Kentucky's other customer to subsidize these projects. The amendments to the Company's cogeneration tariffs have not been challenged by any intervenor and should be approved.

5. The Company's Proposed Updates to its Service Regulations are Reasonable

The Company is proposing revisions and updates to several rate schedules, including: (1) Service Regulation Section V (Metering) and Section VI (Billing & Payment); (2) Sheet No. 98 (Electric Emergency Procedures for Long-Term Fuel Shortages; (3) Sheet No. 100 (Emergency Electric Procedures; (4) Sheet No. 96 (Underground Residential Distribution Policy (Rate UDP-R)); and (5) Sheet No. 97 (General Underground Distribution Policy (Rate UDP-G)).[732] In response to Staff data requests, the Company provided revised language for Service Regulation

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[728] *See* Sailers Direct, p. 18.

[729] *See id.*

[730] *See id.*

[731] *See id.*

[732] *See id.*, p. 22.

Section VI (Billing & Payment) to accommodate the budget payment plan and fixed bill payment option.[733] All of these tariff updates should be approved.

6. The Company's Proposal to Eliminate Tariffs that have been Previously Withdrawn, have Expired, or are no Longer in use is Reasonable

Duke Energy Kentucky proposes to delete Rate RTP-M, Rate OL and Rate NSP from its tariff. The Rate RTP-M class is not populated with any customers and no customer has ever taken service under it.[734] The tariff is a vestige of the time when the Company purchased all of its energy from Duke Energy Ohio.[735] It should be noted that the RTP-M is separate and different from the Company's voluntary Real Time Pricing (Rate RTP) Experimental Real Time Pricing Program for customers that wish to manage their load in response to market price signals. Likewise, Rate OL and Rate NSP were set to expire by their own terms. No party has objected to the elimination of these tariffs and the Company's proposal to update its tariff should be accepted.

7. The Company's Proposed Change to its Rider FAC is Reasonable

Duke Energy Kentucky also seeks to modify its Rider FAC so as to include eligible fuel and purchased power-related charges that are assessed by PJM, but that are not currently recovered through Rider FAC.[736] The Company's current Rider FAC was implemented in 2007, when the Company was still a member of MISO.[737] When the Company transitioned to PJM, the BLI codes used by PJM were different than those used by MISO.[738] The Company is proposing changes to ensure that the Company is recovering all of its costs (and flowing through all credits) related to

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[733] *See* Company Response to Staff DR-03-010.

[734] *See* Sailers Direct, p. 19.

[735] *See id.*

[736] *See id.*, p. 16.

[737] *See* Wathen Direct, p. 11.

[738] *See id.*; Swez Direct, pp. 15-16.

fuel and purchased power that are incurred to serve its Kentucky retail customers.[739] A list of the BLIs that the Company proposes to include in the FAC were filed with the Application as Attachment JDS-4 to the Direct Testimony of Company witness John D. Swez.[740] No intervenor has objected to the Company's update to its Rider FAC. For the foregoing reasons, the Company respectfully requests the Commission to authorize the inclusion of costs and credits from the identified BLIs for recovery through Rider FAC.

8. The Company's Proposed Changes to Rider LM are Reasonable

The Company no longer utilizes magnetic tape recording devices as set out in Section II of Rider LM.[741] The Company is proposing to eliminate this provision of the tariff and combine all current Rider LM participants into interval data recorders and time of use meters under Section I of the tariff.[742] No intervenor has challenged the Company's proposal, which should be accepted.

9. The Company's Proposed Update to its CATV Rate is Reasonable

The Company is proposing to update the calculation for its CATV Rate in accordance with the Commissions Administrative Case 251.[743] The Company is also proposing to expand the tariff to apply the per foot charge to other pole attachments on a contract basis.[744] For this reason, the Company proposes to rename the tariff as Rate Distribution Pole Attachment (Rate DPA).[745] No intervenor has challenged the Company's proposal, which should be approved.

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[739] *See* Wathen Direct, p. 11.

[740] *See* Swez Direct. pp. 19-20.

[741] *See* Sailers Direct. p. 17.

[742] *See id.*

[743] *See id.*, p. 18.

[744] *See id.*, p. 19.

[745] *See id.*

10. The Company's Proposed Update to Rate RTP is Reasonable

Duke Energy Kentucky is not proposing any structural changes to Rate RTP, but proposes to combine the Energy Delivery Charge and Ancillary Services Charge in accordance with the Company's cost of service study.[746] The Company has also proposed a revision to fix a typographical error in the tariff.[747] No intervenor has challenged the Company's proposal, which should be approved.

11. Other Matters

a. Miscellaneous Charges

The Company is proposing to adjust two miscellaneous charges. First, the Company proposes to rename the Meter Data Charges rate as the Meter Data Charges for Enhanced Usage Data Services (Rate MDC).[748] The name change more appropriately reflects the purpose of the service provided pursuant to the tariff. Second, in the Generation Support Service tariff (Rider GSS), the Company proposes to combine: (1) the Monthly Distribution Reservation Charge; (2) the Monthly Transmission Reservation Charge; and (3) the Monthly Ancillary Services Reservation Charge into a single monthly charge now called a Monthly Transmission and Distribution Reservation Charge, as updated in the cost of service study.[749]

The Company also proposes to revise several reconnection of service charges as follows: \$75 for reconnection that cannot be accomplished remotely; \$88 for a non-remote, combined reconnection of gas and electric service; \$125 for reconnection at the pole (\$150 if gas is also reconnected); and an incremental charge of \$25 for all non-remote reconnections after normal

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[746] *See id.*

[747] *See id.*

[748] *See id.*, p. 20.

[749] *See id.*

business hours.[750] The Company originally proposed a $25 reconnection charge for services that may be reconnected remotely,[751] but subsequently agreed to lower the charge to $3.45 for a remote reconnection.[752] Because a certain amount of revenue relating to remote reconnection charges at the higher rate was included as an offset (reduction) to the Company's forecasted test year revenue requirement,[753] it would be necessary to increase the revenue requirement by for Rate RS by $165,124 and for Rate DS by $5,635.[754]

b. Tariff SP Should Not be Reopened

Mr. Willhite recommends that Tariff SP should be reopened for new customers.[755] Tariff SP was established decades ago to apply to sports fields. This tariff was closed effective June 25, 1981 and has remained such for more than thirty-six years. However, the Company's experience proved that there was limited interest in Tariff SP and it was subsequently closed to new members.[756] There is no reason that has been articulated by Mr. Willhite or the KSBA to reopen Tariff SP. Indeed, the Company's current billing system does not even allow it to determine how many customers may be eligible to participate in the tariff should it be reopened.[757] Since this issue was not included in the Company's Application, the burden of proof to establish the reasonableness of re-opening Rate SP falls to KSBA. It has failed to satisfy that burden of proof in this case and Mr. Willhite's recommendation should not be adopted.

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[750] *See id.*, p. 21.

[751] *See id.*

[752] *See* Company Response to AG DR-02-040; Bruce L. Sailers Rebuttal Testimony (Sailers Rebuttal), p. 15 (filed Feb. 14, 2018).

[753] *See* Company Response to Staff DR-02-067a.

[754] *See* Sailers Rebuttal, p. 15.

[755] *See* Ronald Willhite Direct Testimony (Willhite Direct), p. 9 (filed Dec. 29, 2017).

[756] *See* HVR 3:28:20 (Mar. 7, 2018).

[757] *See id.*, 3:30:40.

c. There is no Justification to Create a Rate P-12 Class

Likewise, Mr. Willhite also proposed a separate rate class should be established to benefit P-12 schools.[758] However, he provides no information that specifically demonstrates how schools have energy demand requirements that are substantially dissimilar from other customers within Rate DS. While schools are generally less occupied during the months of June and July, Mr. Willhite acknowledged that there are still several activities that take place during these months.[759] The alleged dip in energy usage that schools have during the summer months is fully-recognized in lower volumetric energy charges.[760] Moreover, the fixed costs of serving a school do not change based upon the months in which schools are in session.[761] For these reasons, KSBA has failed to demonstrate why a new Rate P-12 Class is necessary and the proposal should be rejected.

d. The Company Should Not be Required to Fund the School Energy Management Program

Mr. Willhite, on behalf of KSBA, recommends that the Commission should compel Duke Energy Kentucky to fund the School Energy Management Program (SEMP).[762] While the recommendation is no doubt well-intentioned, it is not supported by evidence. As an initial matter, Mr. Willhite fails to demonstrate that SEMP is the proximate cause of the energy efficiency gains that school districts in the Company's service territory have achieved.[763] Nor does he offer any evidence that shows the Company's choice not to fund SEMP to date has somehow prevented school districts in the Company's service territory from moving forward with meaningful energy

[758] *See* Willhite Direct, pp. 7-8.

[759] *See* HVR 5:49:20 (Mar. 7, 2018).

[760] *See id.*, 6:08:20.

[761] *See id.*, 3:55:00.

[762] *See* Willhite Direct, p. 12.

[763] *See* Alexander "Sasha" J. Weintraub, Ph.D. Rebuttal Testimony (Weintraub Rebuttal), p. 2 (Feb. 14, 2018).

efficiency programs.[764] The only actual evidence presented in the case points to the contrary. Since 2014, Duke Energy Kentucky has paid nearly $1 million in DSM incentives to customers with energy efficiency projects at P-12 schools.[765] Likewise, approximately 10% of the 400+ schools listed as Energy Star® certified are served by Duke Energy Kentucky.[766] The bottom line is that there is no credible evidence to suggest that a dedicated funding stream to SEMP will provide a greater incentive for energy efficiency in P-12 schools than already exists through the Company's existing DSM programs. For this reason, KSBA's recommendation should be rejected.

e. The Rate DS Demand Ratchet is Reasonable as Applied to Schools

In the course of the hearing, Mr. Willhite testified that the demand ratchet currently applicable to P-12 Schools receiving service under Rate DS was unreasonable.[767] However, in cross-examination, it was clarified that the ratchet applies only to the demand portion of the rate and not the volumetric or customer charges.[768] The demand ratchet is a well-known tariff mechanism that assures that a customer's demand is set based upon a clear price signal. Mr. Willhite provided no evidence to support his claim that the demand ratchet in Rate DS should not apply to P-12 schools. To the contrary, such a carve-out would amount to an unreasonable rate discrimination, which is prohibited under Kentucky law.[769] Accordingly, in the absence of affirmative evidence to the contrary, Mr. Willhite's opinion is more in the nature of advocacy and should be disregarded.

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[764] *See id.*, p. 3.

[765] *See id.*

[766] *See id.*

[767] *See* HVR 6:04:04 (Mar. 7, 2018).

[768] *See id.*, 6:08:10.

[769] *See* KRS 278.170.

E. The Company's Proposed Amortization of Various Existing Regulatory Assets and Rate Case Expense is Reasonable

Since the conclusion of the Company's last electric base rate case, it has incurred several extraordinary expenses which have caused it to seek and obtain regulatory assets from the Commission. As part of its Application, Duke Energy Kentucky is now proposing to amortize these assets, which include expenses related to: (1) Hurricane Ike storm restoration costs; (2) research and development investments; (3) incremental O&M and incremental depreciation expense related to the Company's acquisition of the entirety of East Bend; and (4) AMI deployment-related expenses.[770] In addition, the Company seeks to amortize the unrecovered depreciation expense arising from the acquisition of DP&L's 31% interest in East Bend and to amortize its costs of presenting this rate case. Each of these expenses is described more particularly below.

1. Hurricane Ike Restoration Costs

In Case No. 2008-00476,[771] the Commission authorized the Company to establish a regulatory asset to account for storm restoration costs associated with Hurricane Ike. The projected balance for this regulatory asset as of March 31, 2018, is $4,912,800,[772] which the Company proposes to recover over five years.[773] The effect of the adjustment on electric operations is an increase in the pre-tax operating expenses of $982,560 per year.[774] No party as challenged the Company's proposed amortization and it should be approved.

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[770] *See* Application, ¶ 11.

[771] *See In the Matter of: Application of Duke Energy Kentucky, Inc. for an Order Approving the Establishment of a Regulatory Asset*, Order, Case No. 2008-00476 (Ky. P.S.C. Jan. 7, 2009).

[772] *See* Wathen Direct, p. 33 *citing* Application Schedule D-2.31.

[773] *See id.*, p. 34.

[774] *See* Lawler Direct, p. 12.

2. Carbon Management Research and Development Investments

In Case No. 2008-00308,[775] the Commission authorized the Company to establish a regulatory asset to account for costs associated with contributions towards carbon management research. The research was undertaken by the Carbon Management Research Group partnership through the University of Kentucky Center for Applied Energy.[776] The projected balance for this regulatory asset as of March 31, 2018 is $2,000,000,[777] which the Company originally proposed to recover over five years.[778] To conform the amortization to the Company's original request in Case No. 2008-00308, the Company now requests a ten-year amortization, which amounts to amortization expense of $200,000 per year.[779] No intervenor has objected to this amortization schedule and it should be approved.

3. Incremental O&M Expense From the Acquisition of DP&L's Interest in East Bend

In Case No. 2014-00201,[780] the Commission authorized the Company to establish a regulatory asset to track for O&M expenses related to the Company's acquisition of DP&L's interest in the East Bend Generating Station. The projected balance for this regulatory asset as of March 31, 2018 as originally provided by the Company was $39,162,337,[781] which the Company

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[775] *See In the Matter of: Joint Application of Duke Energy Kentucky, Inc., Kentucky Power Company, Kentucky Utilities Company and Louisville Gas and Electric Company for an Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities Related to Certain Payments Made to Carbon Management Research Group and the Kentucky Consortium for Carbon Storage,* Order, Case No. 2008-00308 (Ky. P.S.C. Oct. 30, 2008).

[776] *See* Lawler Direct, p. 13.

[777] *See* Wathen Direct, p. 33 *citing* Application Schedule D-2.31.

[778] *See id.*, p. 34.

[779] *See* Lawler Rebuttal, p. 5.

[780] *See In the Matter of: Application of Duke Energy Kentucky, Inc. for (1) A Certificate of Public Convenience and Necessity Authorizing the Acquisition of the Dayton Power & Light Company's 31% Interest in the East Bend Generating Station; (2) Approval of Duke Energy Kentucky, Inc.'s Assumption of Certain Liabilities in Connection with the Acquisition; (3) Deferral of Costs Incurred as Part of the Acquisition; and (4) All Other Necessary Waivers, Approvals, and Relief*, Order, Case No. 2014-00201 (Ky. P.S.C. Dec. 4, 2014).

[781] *See* Wathen Direct, p. 33 *citing* Application Schedule D-2.31.

proposed to recover over ten years.[782] Mr. Kollen recommends a reduction in the Company's regulatory asset to reflect actual deferrals through October 2017 and to revise the forecast for the months of November 2017 through March 2018.[783] The result of Mr. Kollen's adjustment is to reduce the projected regulatory asset balance from the Company's proposed $39.162 million to $35.870 million, and reducing the revenue requirement of $0.406 million related to the amortization of this regulatory asset.[784] However, Mr. Kollen's calculation fails to use the most recent historical data and includes some clerical and computational errors.[785] Accounting for these discrepancies and using the most recent historical data leads to a new projected deferral account balance of $36.540 million as of March 31, 2018, resulting in annual amortization of $4.490 million,[786] which is a $0.323 million reduction in the Company's revenue requirement.[787] The updated amortization should be approved.

4. Depreciation Expense From the Acquisition of DP&L's Interest in East Bend

In Case No. 2015-00120,[788] the Commission authorized the Company to establish a regulatory asset to track the unrecovered depreciation expense arising from the acquisition of DP&L's 31% interest in East Bend. The regulatory asset accounts for the difference in annual depreciation expense resulting from application of FERC-required depreciation calculations and the amount originally intended by the Company to recover the interest purchased over the

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782 *See id.*, p. 34.

783 *See* Kollen Direct, pp. 29-30.

784 *See id.*, pp. 30-31.

785 *See* Wathen Rebuttal, pp. 17-18 (Corrected on Mar. 5, 2018).

786 *See id.*, pp. 17-18, Attachment WDW-Rebuttal-3 (Corrected on Mar. 5, 2018).

787 *See* Lawler Rebuttal, p. 5 (Corrected on Mar. 5, 2018).

788 *See In the Matter of: Application of Duke Energy Kentucky, Inc. for an Order Approving the Establishment of a Regulatory Asset for the Depreciation Expense of its East Bend Unit 2 Generating Station,* Order, Case No. 2015-00120 (Ky. P.S.C. Aug. 20, 2015).

remaining life of East Bend.[789] As of March 31, 2018, the regulatory asset is $11,529,520,[790] which results in an annual amortization figure of $490,618.[791] The proposed amortization should be approved.

5. AMI Deployment-Related Deferral Accounts

The Company seeks to amortize and recover two regulatory assets that are related to its AMI deployment program. The first regulatory asset arises from the undepreciated value of existing meters replaced as part of the AMI deployment. The second regulatory asset arises from the non-recurring and extraordinary expenses incurred by the Company as part of the deployment effort.

a. Meter Change Outs

In Case No. 2016-00152,[792] the Commission authorized Duke Energy Kentucky to establish a regulatory asset to account for the actual costs of the balance of the undepreciated value of the existing metering infrastructure, including inventory, upon retirement of the meters as part of the Company's AMI metering upgrade project.[793] The Company estimates the amount of the regulatory asset to be $6,958,958, which yields an annual amortization expense of $463,931,[794]

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789 *See* Lee Direct, p. 8.

790 *See* Wathen Direct, p. 33 *citing* Application Schedule D-2.21.

791 *See* Lee Direct, p. 8; Wathen Direct, p. 34.

792 *See In the Matter of: Application of Duke Energy Kentucky, Inc. for (1) A Certificate of Public Convenience and Necessity Authorizing the Construction of an Advanced Metering Infrastructure; (2) Request for Accounting Treatment; (3) All Other Necessary Waivers, Approvals, and Relief*, Order, Case No. 2016-00152 (Ky. P.S.C. May 25, 2017).

793 *See* Lee Direct, p. 7.

794 *See* (Corrected on Mar. 5, 2018). Ms. Lee also explained the method for calculating the estimated value of the regulatory asset and explained how the final balance would be trued-up upon the completion of the AMI upgrade project.

which the Company proposes to recover over fifteen years.[795] The request has not been challenged and should be approved.

b. O&M Expense and IT Cost for Residential Opt-Outs

The Commission also authorized a deferral account for AMI opt-out expenses in the same proceeding. The Company estimates the amount of the AMI opt-out regulatory asset to be $263,029 as of March 31, 2018,[796] which the Company proposes to recover over five years,[797] at a rate of $52,606 per year.[798] No intervenor has challenged the Company's proposal, which should be accepted.

6. Rate Case Expenses

It is widely-accepted that a utility is entitled to recover the reasonable actual cost of preparing and presenting a rate case, typically over a three-year period.[799] In this case, the Company included an original estimate of rate case expense,[800] and tendered regular updates as to its actual rate case expense throughout the course of the proceeding. As of March 31, 2018, the total amount of rate case expense incurred by the Company is $657,434.[801] Although precedent would indicate that it should be allowed to recover the rate case expense more quickly, Duke

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[795] *See* Wathen Direct, p. 34 *citing* Application Schedule D-2.16.

[796] *See* Wathen Direct, p. 33 *citing* Application Schedule D-2.31.

[797] *See id.*, p. 34.

[798] *See* Lawler Direct, p. 14.

[799] *See e.g. In the Matter of the Application of Big Rivers Electric Corporation for an Adjustment in Rates*, Order, Case No. 2012-00535 (Ky. P.S.C. Oct. 29, 2013); *In the Matter of the Application of Meade County Rural Electric Cooperative Corporation to Adjust Electric Rates*, Order, Case No. 2010-0022 (Ky. P.S.C. Feb. 17, 2011) (reciting the "Commission's longstanding practice of allowing rate case expenses based on the most recent actual costs filed by the utility.")

[800] *See* Application Schedule D-2.17 and Schedule F-6.

[801] *See* Company's Sixth Supplemental Response to Staff DR-01-059 (filed Apr. 2, 2018).

Energy Kentucky respectfully requests that this amount be recovered over five years.[802] No intervenor has objected to this request.

F. The Company's Request for Deferral Accounting is Reasonable

Finally, the Company seeks to establish deferral accounting for certain cost items. In particular, Duke Energy Kentucky seeks Commission authorization to establish deferral accounts to track actual costs for planned maintenance outages and incremental purchased power expenses related to forced outages that are not otherwise recovered through the Company's Rider FAC. The deferral authority will allow the Company to debit or credit regulatory asset accounts when actual expenses for these costs in a year are under or over the amount established in base rates in this proceeding.[803] The Commission has previously authorized Duke Energy Kentucky and other jurisdictional utilities to establish regulatory assets. The Commission has exercised its discretion to approve regulatory assets where a utility has incurred: (a) an extraordinary, nonrecurring expense which could not have reasonably been anticipated or included in the utility's planning; (b) an expense resulting from a statutory or administrative directive; (c) an expense in relation to an industry sponsored initiative; or (d) an extraordinary or nonrecurring expense that over time will result in a saving that fully offsets the cost.[804]

Duke Energy Kentucky proposes to defer, with carrying charges based upon the Company's cost of debt approved in this proceeding,[805] on an annual basis any such over recovery or under

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[802] The Company reserves the right to seek recovery of rate case expense in future cases over a three-year period.

[803] *See* Application, ¶ 42.

[804] *See In the Matter of the Application of East Kentucky Power Cooperative, Inc. for an Order Approving Accounting Practices to Establish a Regulatory Asset Related to Certain Replacement Power Costs Resulting from Generation Forced Outages*, Order, Case No. 2008-00436, p. 4 (Ky. P.S.C., Dec. 23, 2008); *In the Matter of Application of East Kentucky Power Cooperative, Inc. for an Order Approving the Establishment of a Regulatory Asset for the Amount Expended on Its Smith 1 Generating Unit*, Order, Case No. 2010-00449, p. 7 (Ky. P.S.C., Feb. 28, 2011).

[805] *See* David L. Doss, Jr. Direct Testimony (Doss Direct), p. 7 (filed Sep. 1, 2017).

recovery and establish a regulatory liability or asset as may be required.[806] Each year, an incremental amount over or under, what is established in base rates, will be added to or subtracted from the total balance deferred.[807] Duke Energy Kentucky further proposes that any regulatory asset or liability created be reviewed for recovery through amortization as part of the Company's next base electric rate case.[808]

1. A Deferral Account is Needed to Track Costs for Planned Maintenance Outages

The Company's forecasted test year budget for outage maintenance expense and replacement power costs for East Bend and Woodsdale have been adjusted to reflect a representative *(i.e.,* average) level of expense.[809] Outage maintenance expense has been normalized based upon four years of actual maintenance expense and two years of projected maintenance expenses.[810] Actual expenses incurred for planned maintenance outages will always vary significantly from what is in base rates for Duke Energy Kentucky as the planned outage activity for its major generating station is on a twenty-four month cycle, meaning in one year the costs will be high and will be lower in the off year. If base rates reflect the average of planned outage costs over a number of years, actual costs will necessarily be significantly different than the amount recovered in base rates. Deferral accounting will smooth out the earnings impact of this "off" and "on" major expense. Permitting the Company to defer for future recovery any incremental amount over or under what is established in base rates for this expense will ensure that

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806 *See* Application, ¶ 42.

807 *See id.*

808 *See id.*

809 *See* Doss Direct, p. 5.

810 *See id.*

customers are not over-paying and the Company is not under recovering for actual costs incurred in serving customers.[811]

On behalf of the AG, Mr. Kollen supported the inclusion of an average of planned outage costs in base rates,[812] but objected to the establishment of a deferral account for planned outage O&M expense on the belief that it would "remove the Company's behavioral incentive to minimize the cost of planned outages."[813] Mr. Kollen acknowledged, however, that the Commission has previously authorized both KU and LG&E to establish identical deferral accounts,[814] which is telling, given the fact that KU and LG&E have significantly more generation assets than Duke Energy Kentucky and, as a result, less exposure to planned maintenance outage expense.[815] Mr. Kollen's position is also inconsistent with his own opinion supporting the establishment of a deferral account for replacement power expenses due to forced outages. A comparison of the two types of charges shows Duke Energy Kentucky's exposure to volatility from planned outage costs is similar to the volatility it experiences from replacement power costs for forced outages.[816]

Establishing a deferral account will not incentivize the Company to let planned outage expenses run wild. Instead, it provides a level of protection against volatility that is more common for a small utility such as Duke Energy Kentucky.[817] Moreover, the mere establishment of a

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[811] *See* Application, ¶ 43.

[812] *See* Section III.C.3.d., *supra*.

[813] *See* Kollen Direct, pp. 17-18.

[814] *See* HVR 4:04:14 (Mar. 8, 2018); Wathen Rebuttal, p. 13; *see also In the Matter of: Electronic Application of Kentucky Utilities Company for an Adjustment of its Electric Rates and for Certificates of Public Convenience and Necessity*, Order, Case No. 2016-00370 (Ky. P.S.C. June 22, 2017; *In the Matter of: Electronic Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates and for Certificates of Public Convenience and Necessity*, Order, Case No. 2016-00371 (Ky. P.S.C. June 22, 2017).

[815] *See* Wathen Rebuttal, pp. 15-16.

[816] *See id.*, p. 15 and Company's Response to Staff's Post-Hearing DR-01-012.

[817] *See* Doss Direct, p. 6.

deferral account does not in any way equate to an abdication by the Commission of its right to assure that all costs are prudently incurred. Plainly, the Commission has the experience and judgment to determine if any deferred account should ultimately be recovered through rates. The requested deferral account is a good tool for mitigating the impact of volatility in the Company's expenses and helps protects customers from that volatility. The AG's recommendation to not establish a deferral account in this instance should be denied.

2. A Regulatory Account is Needed to Track Incremental Purchased Power Expenses Related to Forced Outages not Otherwise Recovered through the Company's Rider FAC

Replacement power costs reflect the forecasted amounts from the GenTrader production cost model for the test period.[818] Permitting the Company to defer for future recovery any incremental amount over or under what is established in base rates for this expense will ensure that customers are not over paying and the Company is not under recovering for actual costs incurred in serving customers.[819] As with the expense for planned maintenance outages, actual expenses incurred for forced outage replacement power, whether above or below the estimated amount included in base rates are, by definition unanticipated and extraordinary. They too are heavily dependent upon the prevailing energy prices at the time of the forced outage.[820]

The AG's witness, Mr. Kollen, agreed that deferral accounting was appropriate in this context.[821] While the dispute as to how much expense should be factored into the Company's revenue requirement has been previously addressed,[822] there is no dispute that establishing the regulatory asset account is necessary and proper. Accordingly, the Commission should grant Duke

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[818] *See id.*, p. 5.

[819] *See id.*

[820] *See* Company Response to AG DR-01-011b (revised).

[821] *See* Kollen Direct, p. 12.

[822] *See* Section III.C.3.c., *supra*.

Energy Kentucky the authority to establish a deferral account to track the incremental costs or credits arising from replacement power expense that exceeds or trails the amount of such expense included in base rates. No intervenor has challenged the Company's proposal, which should be accepted.

IV. Conclusion

The Company's request for a rate increase is reasonable, as are its requested ROE, requests to amortize various regulatory assets, updates and amendments to its tariffs and request to establish new deferral accounts. Duke Energy Kentucky respectfully requests the Commission to consider the evidence summarized herein and give the testimony of each witness the weight to which it is entitled based upon each witnesses' personal knowledge and direct experience. The record is now complete and the case stands submitted for the Commission's decision.

WHEREFORE, in light of the authorities cited and evidence summarized herein, the Company hereby respectfully requests the Commission to grant it the following relief:

1) Approve the Company's base period and forecasted test year;

2) Approve an authorize an increase in the Company's electric base rates to achieve a $30,119,059 increase in the Company's revenue requirement;

3) Approve the Company's revised capitalization of $693,022,202;

4) Authorize a 10.3% allowed return on equity;

5) Approve the Company's 12-CP Cost of Service Study;

6) Authorize the Company to refund excess protected ADITs in accordance with the ARAM methodology set forth in law;

7) Authorize the Company to refund excess unprotected ADITs over twenty (20) years;

8) Accept the Company's Depreciation Study and establish depreciation rates consistent therewith;

9) Authorize the Company to increase its customer charges as set forth in the record herein;

10) Authorize the Company to allocate the increase in rates authorized by the Commission as set forth in the record herein;

11) Authorize the Company to implement Rider DCI;

12) Authorize the Company to implement Rider ESM, as updated herein, and retire the ash pond ARO as set forth herein;

13) Approve the Company's proposed Environmental Compliance Plan;

14) Authorize the Company to implement Rider FTR;

15) Authorize the Company to amend Rider PSM, as updated herein;

16) Authorize the Company to implement the Fixed Bill program;

17) Authorize the Company to amend its street lighting tariffs and implement Rate LED;

18) Authorize the Company to amend its QF Small Tariff and QF Large Tariff;

19) Authorize the Company to update its Service Regulation Tariffs;

20) Allow the Company to eliminate withdrawn and expired tariffs from its schedule of rates;

21) Authorize the Company to amend Rider FAC as set forth herein;

22) Authorize the Company to update Rider LM;

23) Authorize the Company to update its CATV Rate;

24) Authorize the Company to update its Rate RTP;

25) Authorize the Company to amend Rate TT;

26) Authorize the Company to update Rate MDC;

27) Authorize the Company to update Rider GSS;

28) Authorize the Company to charge the amounts set forth herein for reconnection fees;

29) Overrule the KSBA's request to reopen Rate SP;

30) Overrule the KSBA's request to require Company shareholders to make contributions to SEMP;

31) Overrule the KSBA's request to establish a Rate P-12;

32) Approve the Company's request to amortize Hurricane Ike restoration costs as set forth herein;

33) Approve the Company's request to amortize Carbon Management Research and Development Investments as set forth herein;

34) Approve the Company's request to amortize incremental O&M expense from the Company's acquisition of DP&L's interest in East Bend;

35) Approve the Company's request to amortize depreciation expense from the Company's acquisition of DP&L's interest in East Bend;

36) Approve the Company's request to amortize meter change out costs associated with the Company's AMI deployment;

37) Approve the Company's request to amortize O&M expense and IT costs associated with the Company's AMI deployment;

38) Authorize the Company to recover the rate expense set forth herein over five years;

39) Authorize the Company to establish a deferral account to track costs for planned maintenance outages;

40) Authorize the Company to establish a deferral account to track costs for purchased power expenses related to forced outages not otherwise recovered through Rider FAC;

41) Overrule all requests of all intervenors not specifically and expressly agreed to by the Company herein; and

42) Grant all other relief to which the Company may be entitled.

Done this 2nd day of April, 2018.

Respectfully submitted,

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CERTIFICATE OF SERVICE

This is to certify that the foregoing electronic filing is a true and accurate copy of the document being filed in paper medium; that the electronic filing was transmitted to the Commission on April 2, 2018; that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding; and that a copy of the filing in paper medium is being delivered via hand delivery to the Commission on the 3rd day of April, 2018.

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