COMMONWEALTH OF KENTUCKY

BEFORE THE
KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
ELECTRONIC APPLICATION OF	)	
LOUISVILLE GAS AND ELECTRIC	)	
COMPANY FOR AN ADJUSTMENT OF ITS	)	
ELECTRIC AND GAS RATES, A	)	**Case No. 2020-00350**
CERTIFICATE OF PUBLIC CONVENIENCE	)	
AND NECESSITY TO DEPLOY ADVANCED	)	
METERING INFRASTRUCTURE,	)	
APPROVAL OF CERTAIN REGULATORY	)	
AND ACCOUNTING TREATMENTS, AND	)	
ESTABLISHMENT OF A ONE-YEAR	)	
SURCREDIT	)	

Direct Testimony of Justin Bieber

on behalf of

The Kroger Co.

March 5, 2021

Direct Testimony of Justin Bieber

Introduction

Q. Please state your name and business address.

A. My name is Justin Bieber. My business address is 111 E Broadway, Suite 1200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Senior Consultant for Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by The Kroger Co. ("Kroger"). Kroger is one of the largest retail grocers in the United States and operates over 28 stores and other facilities in the territory served by Louisville Gas and Electric Company ("LG&E" or the "Company"). Combined, Kroger facilities purchase more than 70 million kWh annually from LG&E.

Q. Please describe your professional experience and qualifications.

A. My academic background is in business and engineering. I earned a Bachelor of Science in Mechanical Engineering from Duke University in 2006 and a Master of Business Administration from the University of Southern California in 2012. I am also a registered Professional Civil Engineer in the state of California.

I joined Energy Strategies in 2017, where I provide regulatory and technical support on a variety of energy issues, including regulatory services, transmission and renewable development, and financial and economic analyses. I have also filed and supported the development of testimony before various state utility regulatory commissions.

Prior to joining Energy Strategies, I held positions at Pacific Gas and Electric Company as Manager of Transmission Project Development, ISO Relations and FERC Policy Principal, and Supervisor of Electric Generator Interconnections. During my career at Pacific Gas and Electric Company, I supported multiple facets of utility operations, and led efforts in policy, regulatory, and strategic initiatives, including supporting the development of testimony before and submittal of comments to the FERC, California ISO, and the California Public Utility Commission. Prior to my work at Pacific Gas & Electric, I was a project manager and engineer for heavy construction bridge and highway projects.

Q. Have you testified previously before this Commission?

A. Yes, I testified in Duke Energy Kentucky's 2017 general base rate case and 2019 general base rate case, Case Nos. 2017-00321 and 2019-00271, respectively. I also testified in the Kentucky Utilities Company and Louisville Gas and Electric Company 2018 general base rate cases, Case Nos. 2018-00294 and 2018-00295, respectively.

Q. Have you filed testimony previously before any other state utility regulatory commissions?

A. Yes. I have testified before the Colorado Public Utilities Commission, the Indiana Utility Regulatory Commission, the Michigan Public Service Commission, the Montana Public Service Commission, the Nevada Public Utilities Commission, the North Carolina Utilities Commission, the Public Utilities Commission of Ohio, the Public Utility Commission of Oregon, the Utah Public Service Commission, the Virginia State Corporation Commission, and the Public Service Commission of Wisconsin.

Overview and Conclusions

Q. What is the purpose of your testimony in this proceeding?

A. My testimony addresses the following topics:

(1) LG&E's proposed changes in depreciation rates for the Company's remaining coal-fired generation units;

(2) LG&E's proposal to continue the use of regulatory asset and liability accounting for generator outage expenses; and

(3) A multi-site commercial rate aggregation pilot.

Q. Please summarize your recommendations to the Commission.

A. I offer the following recommendations:

(1) LG&E's proposal to increase its revenue requirement in this proceeding to reflect changes in depreciation rates based on the accelerated retirement of its remaining coal-fired generation units should be denied. Instead, the revenue requirement should be calculated using the existing depreciation rates for LG&E's coal fleet, with the undepreciated balance transferred to a regulatory asset at the time of retirement. The undepreciated balance in the regulatory asset should be amortized over the current depreciable lives of the affected generating

plants. Given the current challenges facing customers and the local economy brought on by the COVID-19 pandemic, and the continuously changing operational and economic circumstances for the Company's coal-fired generation assets, it is not necessary or appropriate to increase the base rate revenue requirement to recover LG&E's significant proposed increase in depreciation expense at this time.

(2) The Commission should deny LG&E's request to continue the use of regulatory asset and liability accounting for generator outage expenses. The proposed accounting treatment is unnecessary and would reduce the Company's incentive to reduce costs as much as possible. This non-precedential accounting treatment resulted from multi-party negotiations in LG&E's prior two general rate cases, Case Nos. 2016-00371 and 2018-00295, and I recommend that it be eliminated going forward.

(3) It is reasonable and appropriate at this time for the Company to initiate a multi-site commercial rate aggregation study in order to provide an opportunity for the Company and its stakeholders to gain insight into how a multi-site aggregation rate would work. A well-designed demand aggregation program places a customer with multiple locations on an equal footing with single-site customers, by charging participating multi-site customers for the amount of generation and transmission services that they actually use, thereby promoting equitable treatment of these customers. To that end, I recommend that the Commission order the Company to study the feasibility of a multi-site aggregate commercial rate

and propose a pilot program it its next rate case that would allow commercial customers to participate in a multi-site rate applicable to the portion of the demand charge associated with fixed production and transmission costs.

<u>Depreciation Rates</u>

Q. Please explain how LG&E is proposing to update depreciation rates for the Company's generation fleet in this proceeding.

A. Company witness Lonnie Bellar explains that the Company has determined that the current retirement dates for its steam generating units are no longer reasonable due to changed circumstances. As such, the Company has determined new retirement dates that it considers to be reasonable estimates of the remaining economic lives of the units.[1] Mr. Bellar provides the existing and updated retirement dates for the affected units, which is reproduced in Table JB-1 below.

[1] Direct Testimony of Lonnie E. Bellar, p. 9.

Table JB-1
LG&E's Current and Updated Retirement Year
For Certain Coal-Fired Generating Units[2]

	Retirement Year	
Unit	**Current**	**Updated**
Brown 3	2035	2028
Ghent 4	2038	2037
Mill Creek 1	2032	2024
Mill Creek 2	2034	2028
Mill Creek 3	2038	2039
Mill Creek 4	2042	2039
Trimble County 1	2050	2045

LG&E witness John Spanos explains that he utilized these probable retirement dates and change in life span for these generating units, as provided by Mr. Bellar, in his depreciation studies.[3]

Q. What factors did LG&E consider in assessing the remaining economic lives of generating units?

A. According to Mr. Bellar, the Company's Generation Planning and Analysis function continuously assesses generation resources as part of the Integrated Resources Planning ("IRP") process. Mr. Bellar explains that the planning process considers a range of factors including the impact of environmental regulations, fuel price scenarios, the cost of replacement generation, risk of catastrophic failures, and the operational and major maintenance costs that may be avoided by economic retirements.[4]

[2] Id.
[3] Direct Testimony of John J. Spanos, p. 10.
[4] Direct Testimony of Lonnie E. Bellar, p. 10.

Q. What is the revenue requirement impact resulting from the proposed changes in depreciation rates for the Company's coal-fired generation units?

A. According to Company witness Kent Blake, the proposed changes in depreciation rates for the Company's coal-fired generation units increased LG&E's depreciation expense by $59.2 million.[5] After considering the effects on capitalization, property taxes, and income taxes, the total LG&E revenue requirement impact resulting from this change in depreciation rates is $50.5 million.[6]

Q. What is your assessment of LG&E's proposal to increase the revenue requirement by $50.5 million in this case to reflect earlier retirement dates for its coal-fired generating resources?

A. I recommend that the Commission deny LG&E's request to increase its base rate revenue requirement by $50.5 million in this case to reflect the accelerated retirement of its coal-fired generating resources. Instead, the revenue requirement should be calculated using the existing depreciation rates for LG&E's coal fleet. I recommend that the Commission authorize LG&E to transfer the remaining undepreciated plant balances to a regulatory asset when these units are retired and amortize the balance over the current depreciable lives. Specifically, this accounting treatment should apply to the coal-fired generating units listed in Table JB-1.

[5] Direct Testimony of Kent W. Blake, p. 21.

[6] Louisville Gas and Electric Company Response to Second Data Requests for Information of the Kroger Co. Dated February 5, 2021, Question No. 7 (a), Reproduced in Exhibit JB-1.

Simply put, it is not appropriate or necessary to increase the depreciation rates for these facilities at this time. As Company witness Paul Thompson acknowledges, the COVID-19 pandemic has created unprecedented challenges for LG&E's customers and communities.[7] LG&E's proposed increase to depreciation rates is a key driver of its significant overall proposed revenue requirement increase of $131.2 million, or 11.6%. My recommendation would help mitigate this proposed increase in costs for LG&E's customers at this very difficult time while also providing a reasonable opportunity for LG&E to recover its costs.

Further, as I explain above, LG&E continuously assesses its generation portfolio as part of the IRP process based on a range of factors. As such, the changing operational and economic circumstances that caused LG&E to propose updated retirement dates for its steam generating units in this proceeding may cause LG&E to update the probable retirement dates again in the future. Maintaining existing depreciation rates for ratemaking purposes will help provide some rate stability and gradualism, as opposed to the significant rate impacts that would result from continuously increasing the depreciation rates for these units.

[7] Direct Testimony of Paul W. Thompson, p. 12.

Q. Company witness Kent Blake claims that the significant changes in facts and circumstances regarding the remaining coal-fired generation fleet must be addressed now in depreciation rates to avoid the risk of stranded assets and inter-generational inequities.[8] How do you respond to these concerns?

A. Utilizing a regulatory asset as I am proposing to recover the Company's remaining undepreciated investment in its coal-fired generating units after these units are retired will provide LG&E a reasonable opportunity to fully recover its investment over the originally expected lives.

Further, the opportunity has come and gone for the Company to fully recover its investment in its coal-fired generating units *and* fully avoid inter-generational inequities. LG&E's proposal to significantly increase its depreciation expense in this case would create an inter-generational inequity by imposing significantly higher costs on current customers for generating units that are becoming increasingly uneconomic, relative to the costs borne by past customers that benefitted from these resources. My proposal to utilize a regulatory asset to recover the Company's remaining investment in its coal-fired generating resources after the plants are retired mitigates some of this burden on current customers, who are also at the forefront of dealing with the challenges and economic circumstances brought on by the COVID-19 pandemic.

[8] Direct Testimony of Kent W. Blake, p. 5.

Q. Are you aware of any past precedent by this Commission approving the use of a regulatory asset to recover the costs of retired assets?

A. I am aware of a couple of instances where this Commission approved the use of a regulatory asset to recover the costs of retired assets. In Kentucky Power Company's ("KPC") Application seeking a Certificate of Public Convenience and Necessity in connection with the transfer of a 50% interest in the Mitchell Generating Station, the Commission approved provisions in a non-unanimous stipulation authorizing KPC to recover retirement costs for the Big Sandy Unit 1 and Unit 2,[9] including net book value and removal costs, on a levelized basis over 25 years.[10] Subsequently, in KPC's 2014 general rate case, the Commission approved the Big Sandy Retirement Rider.[11]

Additionally, the Commission approved Kenergy Corp.'s application to establish a regulatory asset to recover the undepreciated balance of its electro-mechanical meters that were replaced by an Advanced Metering Infrastructure system.[12]

[9] *In the Matter of Application Of Kentucky Power Company For (1) A Certificate Of Public Convenience And Necessity Authorizing The Transfer To The Company Of An Undivided Fifty Percent Interest In The Mitchell Generating Station And Associated Assets; (2) Approval Of The Assumption By Kentucky Power Company Of Certain Liabilities In Connection With The Transfer Of The Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral Of Costs Incurred In Connection With The Company's Efforts To Meet Federal Clean Air Act And Related Requirements; And (5) All Other Required Approvals And Relief,* Case No. 2012-00578, Order (October 7, 2013), p. 43.
[10] Id, Stipulation and Settlement Agreement (July 2, 2013), pp. 9-10.
[11] 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 (June 22, 2015), pp. 45-47.
[12] *In the Matter of Request Of Kenergy Corp. For Approval To Establish A Regulatory Asset In The Amount Of $3,884,717 Amortized Over A Ten (10) Year Period,* Order (August 31, 2015).

Q. Are there any other issues to consider with respect to the early retirement of coal-fired resources and the recovery of undepreciated plant?

A. The carrying costs on the undepreciated balance of coal-fired resources in a regulatory asset driven by early retirement dates could be very significant. One potential tool that the Commonwealth of Kentucky might consider is the use of securitized bonds to refinance the undepreciated plant balances. Generally, the securitization of undepreciated plant would need statutory authorization. However, the cost of securitized bonds would likely be substantially less than the utility regulated rate of return. The use of securitized bonds to refinance undepreciated plant could potentially help mitigate the rate impacts resulting from accelerated coal plant retirements while still providing cost recovery for the utility.

<u>Generator Outage Expense</u>

Q. Please describe LG&E's proposal to recover costs related to generator outage expense in base rates.

A. LG&E's witness Lonnie Bellar explains that LG&E is proposing to normalize outage expense using an 8-year average based on the average actual outage expense for 2017, 2018, 2019, and 2020 through August, combined with forecasted outage expense for the balance of 2020 through 2024. According to Mr. Bellar, an 8-year average including actual and forecast expense is a more accurate and reliable method of normalizing outage expense because major outage maintenance is typically done in 8-year cycles, and because past maintenance costs are not necessarily predictive of future maintenance costs.[13]

Q. Please describe LG&E's proposal regarding the use of regulatory asset and liability accounting for generator outage expenses.

A. In response to discovery, LG&E confirmed that it is proposing to continue the use of regulatory asset and liability accounting for generator outage expenses. According to the Company, this deferral accounting ensures LG&E may ultimately collect, or will have to return to customers, through future base rates any amounts that are above or below the average embedded in the electric revenue requirement increases in these proceedings.[14]

Q. Does LG&E currently use regulatory asset and liability accounting for generator outage expenses?

A. Yes. Mr. Bellar explains that in settling LG&E's prior rate case, the settling parties stipulated to the use of a 5-year historical average and the continued use of regulatory asset and liability accounting for generator outage expense.[15] Similar regulatory asset and liability accounting treatment for generator outage expense was stipulated to by the settling parties in LG&E's 2016 base rate case as well.[16]

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[13] Direct Testimony of Lonnie E. Bellar, p. 23.

[14] Response of Louisville Gas and Electric Company to First Requests for Information of the Kroger Co. Dated January 8, 2021, Question No. 9 (e), reproduced in Kroger Exhibit JB-1.

[15] Direct Testimony of Lonnie E. Bellar, p. 23.

[16] *In the Matter of: Electronic Application of Louisville Gas and Electric Company for an Adjustment of its Electric Rates and for Certificates of Public Convenience and Necessity,* Case No. 2016-00371, Stipulation and Recommendation (April 19, 2017), pp. 6-7.

Q. What is your assessment of LG&E's proposal to continue the use of regulatory asset and liability accounting for generator outage expenses?

A. I recommend that the Commission deny LG&E's proposal to continue the use of regulatory asset and liability accounting for generator outage expenses. Performing generator outage maintenance work is a fundamental responsibility for a utility that does not warrant guaranteed cost recovery. In carrying out this responsibility, utilities are entitled to an opportunity to recover their prudently incurred costs. Allowing LG&E to continue the use of this accounting treatment to guarantee cost recovery for all of its generator outage expense costs above the amount embedded in base rates reduces the Company's incentive to perform the work as efficiently as possible to counterbalance potentially higher costs in other areas, or otherwise increase the utility's earnings.

Q. Are you recommending any other changes regarding the Company's generator outage expense?

A. I am not taking a position regarding the Company's proposal to normalize its generator outage expense using an 8-year average of actual and forecasted expense. Nor am I recommending any changes to the existing generator outage expense regulatory asset. My recommendation is specifically focused on the Company's proposal to continue deferred accounting treatment for future generator outage expenses above or below the amount that is approved to be embedded in base rates.

<u>Multi-site Aggregation Commercial Rate</u>

Q. Please explain multi-site rate aggregation.

A. A multi-site commercial rate aggregation program would allow eligible customers with multiple service locations to aggregate their demands for purposes of power and transmission billing. For a multi-site aggregation program, the billing demand is measured as the highest hourly demand occurring simultaneously across each of a customer's participating locations, thereby measuring billing demand for the totality of the customer's participating sites as if it were a single load for billing purposes. This is described as conjunctive demand billing and should only apply to a customer's generation and transmission service. The distribution portion of the bill should be calculated using demand billing determinants established separately at each location.

Q. Why should the Company study a multi-site commercial rate aggregation program?

A. This type of aggregation properly allows a multi-site customer to capture the diversity within its loads for billing purposes, specifically in the determination of billing demand. By treating the multiple loads of a single customer as a single entity for the purpose of measuring the amount of power and transmission service provided to the customer, the customer's load is treated in a manner that is comparable to the treatment of a single-site customer with the same aggregate load shape. It is also comparable to the way the customer's load would be viewed in a competitive market.

Q. Why is it appropriate to apply a conjunctive demand rate to fixed generation and transmission costs as distinct from distribution costs?

A. Each facility owned by a multi-site customer causes unique distribution costs and therefore it is appropriate to recover those costs based on the peak demand of each individual facility. But that is not the case for fixed production and transmission costs. At the power supply and transmission level, it makes no difference whether 5 MW in a given hour is going to a single-site customer with a 5 MW load or to a multi-site customer with five facilities taking 1 MW each. The cost to produce and transmit the 5 MW in that hour is not materially different.

For a multi-site customer, it would not be unusual for each of its sites to be peaking at a different hour in each month. Under the Company's current rate structures, this means that the customer's cumulative billing demand for fixed production costs would exceed the customer's actual aggregated peak demand measured on an hour-by-hour basis (as if it were a single-site customer). In other words, under the current rate structure, the multi-site customer might be billed for 5.5 MW of fixed production demand based on the sum of the individual peaks of each of its sites (occurring at different hours), whereas in fact, the customer's actual aggregate demand for fixed production demand in any hour might be no greater than 5 MW. A conjunctive demand rate can correct for this upward bias in the billing demand that would otherwise be charged to a multi-site customer by aggregating the customer's billing demands for peak demand measurement purposes. With the proper metering in place, this correction simply charges multi-site customers for the fixed production service that they actually use and places them on an equal footing with single-site customers. Under a well-designed conjunctive demand rate, a multi-site customer that has the same aggregate demand for power supply as a single-site customer pays exactly the same rate and dollar amount for power supply as that single-site customer.

Q. With a multi-site customer rate, would a commercial customer be allowed to aggregate smaller loads onto a different rate schedule designed for larger loads?

A. No, I am not proposing an aggregation program that would allow smaller aggregated loads to qualify for a different rate schedule, but rather simply to better measure the aggregated customer's demand for generation and transmission billing purposes. For example, a customer with five separate sites, each with a maximum billing demand of 100 kW that is currently being billed on the PS Power Service rate, would not be eligible to be billed at the TODS Time of Day Secondary rates designed for customers with loads over 250 kVA.

Q. Are you aware of any well-designed multi-site customer rates?

A. Yes. Consumers Energy in Michigan has such a rate, called the Aggregate Peak Demand Service Provision.[17] This program is available to any customer with 7 accounts or more who desires to aggregate its On-Peak Billing Demands for power supply billing purposes. To be eligible, each account must have a minimum average On-Peak Billing Demand of 250 kW. The aggregated accounts are billed under the same rate schedule and service provisions that apply to the

[17] See Sheet D-63.00 at https://www.michigan.gov/documents/mpsc/Consumers_14_current_675992_7.pdf.

individual sites, with the aggregate maximum capacity to all customers limited to 200,000 kW.

Puget Sound Energy also has a pilot program that was recently approved by the Washington Utilities and Transportation Commission that would allow eligible customers with multiple service locations to aggregate their demands for purposes of power and transmission billing.[18]

Q. What is your recommendation regarding a multi-site commercial aggregation rate?

A. I recommend that the Commission order LG&E to study and propose a conjunctive billing demand pilot program in its next general rate case.

Q. Does this conclude your direct testimony?

A. Yes, it does.

[18] See sheet 26-B at file:///C:/Users/jbieber/Downloads/elec_sch_026.pdf.

VERIFICATION

STATE OF UTAH)
)
COUNTY OF SALT LAKE)

The undersigned, **Justin Bieber,** being duly sworn, deposes and says that he is a Senior Consultant in the firm of Energy Strategies, LLC, that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Justin Bieber

Subscribed and sworn to before me this 5 day of March, 2021, by Justin Bieber.

My commission expires: 4/17/2023

NOTARY PUBLIC

[SEAL]

NOTARY PUBLIC
ALISON MORTAROTTI
COMM. # 705836
COMMISSION EXPIRES
APRIL 17, 2023
STATE OF UTAH

36510:1

Case No. 2020-00350

Exhibit JB-1

Louisville Gas and Electric Company Responses to Data Requests Referenced in Testimony

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to First Requests for Information of the Kroger Company
Dated January 8, 2021**

Case No. 2020-00350

Question No. 9

Responding Witness: Christopher M. Garrett

Q-9. With respect to LG&E's Application, please refer to the Direct Testimony of Lonnie E. Bellar, page 23. "[T]he Companies propose to use average actual outage expense for 2017, 2018, 2019, and 2020 through August, combined with forecasted outage expense for the balance of 2020 through 2024. This approach has the effect of increasing expense associated with outage maintenance, but will ultimately be more accurate than 5-year historical average and will reduce the need to recover past outage expense in future rate increases through regulatory accounting."

a. Please provide LG&E's actual and forecasted outage expense for the proposed 8 year period.

b. Please provide LG&E's actual outage expense for 2012, 2013, 2014, 2015, and 2016.

c. Please explain in detail the reasons why this proposed approach will increase expense relative to using the 5-year historical average.

d. Do the Companies believe that the stipulation from the 2018 rate case that allowed it to continue the use of regulatory asset and liability accounting for generator outage expense sets a precedent to continue to use the same accounting treatment in this case? Please explain why or why not.

e. Please explain why the Companies believe it is appropriate to continue the use of regulatory asset and liability accounting for generator outage expense in this case.

A-9.

a. See the response to AG-KIUC 1-38.

b. See attached.

c. A 5-year historical average for outage maintenance expense is inappropriate to use as a predictor of future outage expense. Major overhauls typically occur about every eight years, depending on the type of generating unit and the condition of the unit as assessed through regular inspections and monitoring. Yearly outage expense for a particular unit will vary depending on when a major overhaul is performed, among other factors. Outage expense may be lower in the years following a major overhaul, and higher as a unit approaches its next major inspection. A five-year historical average does not account for those variations and an 8-year cycle more accurately reflects the aforementioned variations. Additionally, the 5-year historical average utilized in the previous case did not capture outage expense for the Cane Run 7 (CR7) Combined Cycle Gas Turbine unit, commissioned in 2015. An 8-year average also incorporates market conditions associated with the contracting skilled labor and materials market for coal-fired units.

d. The Stipulation and Recommendation approved by the Commission in Case Nos. 2018-00294 and -00295 contains section 1.2 (F), Five-Year Historical Average for Generator Outage Expenses; Related Use of Regulatory Accounting, which states as follows:

> The Parties stipulate to the use of a five-year historical average of generator outage expenses in the Utilities' stipulated amounts provided in Section 1.1, which reduces the Utilities' proposed electric revenue requirement increases as set forth in their applications by $6.73 million for KU and $ 1.78 million for LG&E. Relatedly, the Parties stipulate and recommend Commission approval of the Utilities continuing use of regulatory asset and liability accounting related to generator outage expenses that are greater or less than the updated amount to be included in base rates. This regulatory accounting will ensure the Utilities may collect, or will have to return to customers, through future base rates any amounts that are above or below the base rate base line average embedded in the electric revenue requirement increases in these proceedings.

Comparable language is also contained in Section 2.2(F) in the Stipulation and Recommendation approved by the Commission in Case Nos. 2016-00370 and -00371. If the Commission should order in this case that such normalization be discontinued and use forecast test year expense for ratemaking purposes, it would not be reasonable or lawful to deny the Companies' full cost recovery via amortization of past under-collections under the normalization methodology agreed to and approved by the Commission in the previous four rate cases. The Companies only agreed in the context of a settlement to the incorporation into rates of the artificially low 5-year historic average in the 2018 rate cases based on the cost recovery provided for under the agreed-upon and approved methodology. The Companies' rebuttal testimony demonstrated the historic projections were unreasonable low projections of the expected outages. Actual results have confirmed that position. The true-up in the normalization methodology made it a cash flow timing issue only and not a permanent loss of cost recovery. It is not appropriate to "undo" prior settlement provisions agreed to by all parties unless the modification is also agreed to by all parties and approved by the Commission.[2]

e. The Companies believe it is appropriate to continue the use of regulatory asset and liability accounting for generator outage expenses for the reasons set forth in Mr. Bellar's testimony. Generator outage expenses can fluctuate significantly from year to year; major outages typically occur on an eight-year cycle. Normalization provides a smoothing of what is a cyclical expense – essentially treating it like a capital expense and spreading it over an eight-year period. Use of the forecast test year expense rather than a normalized level in this case would result in general the same combined plant outage cost of about $43 million; however, that is not the case by utility due to the cyclical nature of this type of expense. Past maintenance costs are not necessarily a reasonable estimate of future maintenance costs. Deferral accounting ensures the Companies ultimately may collect, or will have to return to customers, through future base rates any amounts that are above or below the average embedded in the electric revenue requirement increases in these proceedings.[3]

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[2] *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*, Case No. 2017-00179, Order at 5-6, 7-8 (Ky. PSC June 28, 2018); *Electronic Application of Kentucky Power Company for (1) A General Adjustment of Its Rates for Electric Service; (2) Approval of Tariffs and Riders; (3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; (4) Approval of a Certificate of Public Convenience and Necessity; and (5) All Other Required Approvals and Relief,* Case No. 2020-00174, Order at 28-30 (Ky. PSC Jan. 13, 2021).

[3] Case No. 2016-00370 and Case No. 2016-00371, Stipulation and Recommendation, Article II, Section 2.2(F) (Ky. PSC Apr. 19, 2017).

LG&E Outage - Not normalized Unit	FERC	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Actual
0301 - TRIMBLE COUNTY COMMON-GENERATION	510	$ 130,065	$ -	$ -	$ -	$ -
	511		-	-	-	-
	512	9,114	-	-	-	-
	513	(5,985)	-	-	-	-
	514	-	-	-	-	-
0311 - TRIMBLE COUNTY 1 - GENERATION	510	117,774	111,518	99,690	-	-
	511	-	6,261	-	2,327	(987)
	512	(88,130)	945,856	4,464	2,192,311	86,660
	513	40,070	142,810	11,994	300,174	6,218
	514	-	-	-	-	-
0321 - TRIMBLE COUNTY 2 - GENERATION	510	-	-	46,072	-	66,543
	511	-	-	-	727	-
	512	98,354	533	531,445	131,801	299,329
	513	96,893	385	45,075	37,244	223,707
0401 - LGE GENERATION - COMMON	510	37,059	113,441	(213,381)	(90,334)	(7,152)
	513	-	-	-	-	-
0101 - CANE RUN COMMON - GENERATION(1)	510	2,938	-	-	-	-
	513	-	-	-	-	-
0141 - CANE RUN 4 - GENERATION(1)	500	-	-	-	-	-
	510	430,916	-	-	-	-
	511	2,399	-	-	-	-
	512	3,187,195	120,277	468,671	-	-
	513	1,931,469	38,394	83,706	-	-
	514	-	-	-	-	-
0151 - CANE RUN 5 - GENERATION(1)	510		-	-	-	-
	511	-	-	-	-	-
	512	-	955,239	264,620	-	-
	513		217,596	58,038	-	-
	514	-	-	-	-	-
0161 - CANE RUN 6 - GENERATION(1)	510	135,247	-	-	-	-
	511	-	-	282	-	-
	512	1,464,703	319,077	589,175	707	-
	513	362,821	204,896	229,866	394	-
0211 - MILL CREEK 1 - GENERATION	510		278,017	-	426,475	-
	511	-	10,987	-	-	-
	512	68,410	2,538,798	90,155	1,969,498	190,030
	513	3,050	3,081,978	16,606	234,337	125,463
	514		-	-	-	-
0221 - MILL CREEK 2 - GENERATION	510	371,958	9,956	-	394,549	-
	511	-	-	-	-	-
	512	2,842,160	1,688	2,035,209	1,963,564	1,768,972
	513	3,038,156	2,834	235,191	622,480	1,347,379
	514		-	-	-	-
0231 - MILL CREEK 3 - GENERATION	510		338,409	283,456	-	112,896
	511	-	-	-	-	-
	512	250,232	3,252,673	34,968	327,318	2,942,769
	513	172,253	659,233	20,126	124,442	1,775,339
	514	-	124	-	-	-
0241 - MILL CREEK 4 - GENERATION	510	-	-	182,368	162,660	252,274
	511	-	-	-	-	12,335
	512	2,201,066	1,167,712	3,003,378	382,445	2,702,899
	513	684,484	124,182	3,756,372	123,461	574,125
	514	-	-	-	-	-
0172 - CANE RUN CC GT 2016	549	-	-	-	16,661	4,276
	551	-				
	552	-	-	-	1,631	21,191
	553	-	-	-	43,139	219,940
	554	-	-	-	18,166	68,835
0431 - PADDYS RUN GT 12	553	-	27,835	-	-	-

LG&E Outage - Not normalized **Unit**	**FERC**	**2012** **Actual**	**2013** **Actual**	**2014** **Actual**	**2015** **Actual**	**2016** **Actual**
	554	-	-	-	-	-
0432 - PADDYS RUN GT 13	553	(5,967)	43,835	99,436	57,388	76,976
	554	-	409	-	-	-
0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE	553	-	-	-	737	-
5635 - E W BROWN COMBUSTION TURBINE UNIT 5	553	-	-	-	-	-
	554	-	-	-	15,726	-
5636 - E W BROWN COMBUSTION TURBINE UNIT 6	551	-	-	-	-	-
	552	-	-	-	-	-
	553	10,051	16,232	44,418	12,786	4,560
	554		-	-	-	-
5637 - E W BROWN COMBUSTION TURBINE UNIT 7	553	91,402	(24,548)	91,942	(43,973)	20,726
	554					
Total		**$ 17,680,158**	**$ 14,706,633**	**$ 12,113,341**	**$ 9,428,840**	**$ 12,895,303**

(1) Cane Run units 4, 5 and 6 were retired in 2015.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Second Requests for Information of the Kroger Company
Dated February 5, 2021

Case No. 2020-00350

Question No. 7

Responding Witness: Kent W. Blake

Q-7. Refer to the Direct Testimony of Kent Blake, page 21, "the changes in depreciation rates for the Companies' coal-fired generation units recommended by Mr. Spanos and included in the Companies' requested revenue increase added $48.3 million for KU and $59.2 million for LG&E Electric."

a. Please explain in detail how LG&E's proposed revenue requirement in this case would change if the depreciation rates for the Companies' remaining coal-fired generation units were not updated to reflect different retirement dates in this proceeding.

   i. Please provide all relevant workpapers, in excel format, with working formulas included.

b. Please provide a detailed breakdown of the resulting impacts to depreciation expense, income tax expense, property tax expense, rate base, and the return on rate base/capitalization.

   i. Please provide the depreciation expense for each month of the test year that would result if the depreciation rates for the coal-fired generation units are not updated in this proceeding.

   ii. Please identify the change in income tax expense for each month of the test year that would result if the depreciation rates for the coal-fired generation units are not updated in this proceeding.

   iii. Please identify the change in property tax expense for each month of the test year that would result if the depreciation rates for the coal-fired generation units are not updated in this proceeding.

   iv. Please identify the changes to accumulated depreciation and accumulated deferred income tax for each month of the test year that would result if the depreciation rates for the coal-fired generation units are not updated in this proceeding.

v. Please identify the change in return on rate base for each month of the test year that would result if the depreciation rates for the coal-fired generation units are not updated in this proceeding.

vi. Please identify the change in return on capitalization for each month of the test year that would result if the depreciation rates for the coal-fired generation units are not updated in this proceeding.

c. If the resulting impact to LG&E's revenue requirement is different than $59.2 million, as indicated by Mr. Blake, please explain in detail the reasons for this difference.

A-7.

a. The Companies do not agree with the premise of the requested calculation but are providing it to be responsive to the request. See attachment being provided in Excel format.

i. See attachment being provided in Excel format.

b.

i. See attachment being provided in Excel format.

ii. See attachment being provided in Excel format. The Company is providing a simplified presentation for the income tax impacts to avoid having to tax effect the net operating income adjustments (excluding excess ADIT) only to then gross-up those same adjustments for the revenue requirement impact.

iii. See attachment being provided in Excel format.

iv. See attachment being provided in Excel format.

v. See attachment being provided in Excel format.

vi. See attachment being provided in Excel format.

c. For simplicity, the $59.2 million included in the testimony of Mr. Blake referred only to the impact of the rate change on depreciation expense. The other revenue requirement effects detailed in the attachment to this response were reflected within the other drivers discussed in that testimony including the noted changes in capitalization, property taxes and income taxes.

Louisville Gas and Electric Company
Forecasted Test Year Ended June 30, 2022
$ millions

Impact of Not Updating Steam Depreciation Rates

Rate Base/Capitalization	Ref.	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	13 Month Average	
Jurisdictional Accumulated Depreciation	b. iv	-	4.751	9.518	14.296	19.043	24.097	29.159	34.264	39.395	44.499	49.534	54.401	59.179	29.395	
ADIT Change @ Statutory 24.95%	b. iv	-	(1.185)	(2.375)	(3.567)	(4.751)	(6.012)	(7.275)	(8.549)	(9.829)	(11.103)	(12.359)	(13.573)	(14.765)	(5.471)	Prorata ADIT
Jurisdictional Reg Liab Change - Excess ADIT Amort.			(0.384)	(0.768)	(1.152)	(1.536)	(1.920)	(2.303)	(2.725)	(3.147)	(3.568)	(3.990)	(4.411)	(4.833)	(1.751)	Prorata ADIT
KY Jurisdictional Capitalization Adjustment		-	3.182	6.376	9.578	12.756	16.165	19.581	22.990	26.420	29.828	33.185	36.417	39.581	23.924	
Grossed-Up Rate of Return															8.97%	
Rate Base/Capitalization Revenue Requirement Adjustment	b. v/vi		**0.027**	**0.053**	**0.080**	**0.107**	**0.135**	**0.164**	**0.193**	**0.221**	**0.250**	**0.278**	**0.305**	**0.332**	**2.146**	

Net Operating Income	Ref.	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Total
Excess ADIT Amortization Adjustment		0.384	0.384	0.384	0.384	0.384	0.384	0.422	0.422	0.422	0.422	0.422	0.422	4.833
Gross-up Factor - Schedule H		1.337837	1.337837	1.337837	1.337837	1.337837	1.337837	1.337837	1.337837	1.337837	1.337837	1.337837	1.337837	1.337837
Excess ADIT Revenue Requirement Adjustment	b. ii	0.514	0.514	0.514	0.514	0.514	0.514	0.564	0.564	0.564	0.564	0.564	0.564	6.466
Steam Rate Depreciation Adjustment		(4.751)	(4.767)	(4.778)	(4.747)	(5.054)	(5.062)	(5.105)	(5.131)	(5.104)	(5.035)	(4.867)	(4.778)	(59.179)
Property Tax Adjustment at 0.15% Production Rate	b. iii	-	-	-	-	-	-	0.004	0.004	0.004	0.004	0.004	0.004	0.022
Net Operating Income Revenue Requirement Adjustment		**(4.237)**	**(4.254)**	**(4.264)**	**(4.234)**	**(4.540)**	**(4.549)**	**(4.537)**	**(4.563)**	**(4.536)**	**(4.467)**	**(4.300)**	**(4.210)**	**(52.692)**
Total Revenue Requirement Adjustment		**(4.211)**	**(4.200)**	**(4.184)**	**(4.127)**	**(4.404)**	**(4.385)**	**(4.345)**	**(4.342)**	**(4.286)**	**(4.189)**	**(3.995)**	**(3.879)**	**(50.546)**
Depreciation Expense included in Test Year	b. i	**18.027**	**18.026**	**18.064**	**18.151**	**17.928**	**18.099**	**18.163**	**18.126**	**18.157**	**18.242**	**18.418**	**18.542**	**217.943**

Note: The excess ADIT adjustment in this calculation is using the existing amortization methodology, which inlcudes Cost of Removal (COR) components. We are addressing the change to excess ADIT associated with COR per PLR 202033002 in response to AG-KIUC DR2 Q-8(g).

Louisville Gas & Electric

	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Total
Non-Mech Jurisdictional Depreciation and Amortization Included in Test Year Ended June 2022:													
Total Depreciation and Amortization Expense per Schedule C-2.2F	24.1	24.2	24.2	24.3	24.5	24.7	24.8	24.8	24.8	24.8	24.8	24.8	294.8
Times: Depreciation and Amortization Jurisdictional Factor on Schedule C-2.1F	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Subtotal Depreciation and Amortization	24.1	24.2	24.2	24.3	24.5	24.7	24.8	24.8	24.8	24.8	24.8	24.8	294.8
Less: DSM Depreciation per "Rider Adj F" tab of Schedule C	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(1.1)
Less: ECR Depreciation per "Rider Adj F" tab of Schedule C	(1.3)	(1.3)	(1.3)	(1.3)	(1.4)	(1.4)	(1.4)	(1.4)	(1.4)	(1.4)	(1.4)	(1.4)	(16.6)
Jurisdictional Depreciation and Amortization Expense net of Mechanism per C-2.1F	22.8	22.8	22.8	22.9	23.0	23.2	23.3	23.3	23.3	23.3	23.3	23.3	277.1
Non-Mech Jurisdictional Depreciation and Amortization Included in Test Year Ended April 2020:													
Total Depreciation and Amortization Expense per Schedule C-2.2F	18.1	18.2	18.2	18.3	18.3	18.3	18.4	18.6	18.7	18.7	18.7	18.8	221.5
Times: Depreciation and Amortization Jurisdictional Factor on Schedule C-2.1F	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Subtotal Depreciation and Amortization	18.1	18.2	18.2	18.3	18.3	18.3	18.4	18.6	18.7	18.7	18.7	18.8	221.5
Less: DSM Depreciation per "Rider Adj F" tab of Schedule C	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(1.0)
Less: ECR Depreciation per "Rider Adj F" tab of Schedule C	(5.3)	(5.3)	(5.3)	(5.3)	(5.3)	(5.3)	(5.4)	(5.4)	(5.5)	(5.5)	(5.5)	(5.5)	(64.7)
Jurisdictional Depreciation and Amortization Expense net of Mechanism as Filed per C-2.1F	12.7	12.8	12.8	12.9	12.9	12.9	13.0	13.1	13.2	13.2	13.2	13.2	155.8
Less: Depreciation Stipulation Adjustments	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(4.8)
Jurisdictional Depreciation and Amortization Expense net of Mechanism	12.3	12.4	12.4	12.5	12.5	12.5	12.6	12.7	12.8	12.7	12.8	12.8	151.0
Total Change in Depreciation and Amortization Expense between Test Years	10.5	10.4	10.4	10.4	10.5	10.6	10.7	10.6	10.5	10.5	10.5	10.5	126.2
Remove Terminated ECR at Current Depreciation Rates:													
Terminated ECR Depreciation	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	56.1
ECR Jurisdictional Factor	99.7%	99.4%	99.2%	100.0%	93.4%	93.1%	92.3%	91.7%	92.2%	93.7%	97.3%	99.3%	96.0%
Jurisdictional ECR Depreciation Terminated into Base Rates	4.7	4.6	4.6	4.7	4.4	4.4	4.3	4.3	4.3	4.4	4.6	4.6	53.8
Remove Change in Balances from Test Year to Test Year													
Jurisdictional Depreciation and Amortization per UI with no termination and no depreciation rate increase	13.4	13.4	13.4	13.5	13.6	13.7	13.8	13.8	13.8	13.9	13.9	13.9	164.1
Jurisdictional Depreciation and Amortization included in Test Year Ended April 2020 from Above	12.3	12.4	12.4	12.5	12.5	12.5	12.6	12.7	12.8	12.7	12.8	12.8	151.0
Change in Balances from Test Year to Test Year	1.1	1.0	1.0	1.0	1.1	1.2	1.3	1.2	1.1	1.1	1.1	1.1	13.1
Change in Jurisdictional Depreciation Related to Change in Depreciation Rates	4.8	4.8	4.8	4.7	5.1	5.1	5.1	5.1	5.1	5.0	4.9	4.8	59.2

Jurisdictional ADIT on Book Depreciation Change
$ dollars

Prorata ADIT Calculation

Projected Accumulated Deferred Taxes at June 30, 2021			$	-
Projected Accumulated Deferred Taxes at June 30, 2022				(14,765,277)
Decrease in Accumulated Deferred Taxes for the forward year			$	(14,765,277)
				0
	Quarterly Decrease		**Proration**	
Balance June 30, 2021			$	-
July 1- September 30, 2021	$	(3,566,903)	273/365	(2,667,848)
October 1- December 31, 2021		(3,708,382)	181/365	(1,838,951)
January 1- March 31, 2022		(3,827,302)	91/365	(954,204)
April 1- June 30, 2022		(3,662,690)	1/365	(10,035)
Pro rata Balance June 30, 2022			$	(5,471,038)

Excess Deferred Tax Analysis
$ dollars

	Louisville Gas and Electric Company - Total Company			Louisville Gas and Electric Company - Electric			Louisville Gas and Electric Company - Gas		
	ARAM Excess Deferred Tax As-Filed	ARAM Excess Deferred Tax Remove Depr Incr	Difference	ARAM Excess Deferred Tax As-Filed	ARAM Excess Deferred Tax Remove Depr Incr	Difference	ARAM Excess Deferred Tax As-Filed	ARAM Excess Deferred Tax Remove Depr Incr	Difference
2021 July to December	9,099,878	6,661,826	(2,438,052)	8,281,381	5,843,329	(2,438,052)	818,497	818,497	-
2022 January to June	8,578,614	5,914,413	(2,664,201)	7,866,635	5,202,434	(2,664,201)	711,979	711,979	-
Test Year NOL Deficient Amortization	(889,564)	(620,409)	269,155	(851,842)	(582,687)	269,155	(37,722)	(37,722)	-
Forecasted Test Period ending 6/30/22	16,788,928	11,955,830	(4,833,098)	15,296,174	10,463,076	(4,833,098)	1,492,754	1,492,754	-

Prorata ADIT Calculation

	Total Company: Quarterly Decrease	Proration		Electric: Quarterly Decrease	Proration		Gas: Quarterly Decrease	Proration	
Projected Accumulated Deferred Taxes at June 30, 2021			$ -			$ -			$ -
Projected Accumulated Deferred Taxes at June 30, 2022			(4,833,098)			(4,833,098)			0
Decrease in Accumulated Deferred Taxes for the forward year			$ (4,833,098)			$ (4,833,098)			$ -
			0			0			0
Balance June 30, 2021			$ -			$ -			$ -
July 1- September 30, 2021	$ (1,151,737)	273/365	(861,436)	$ (1,151,737)	273/365	(861,436)	$ -	273/365	0
October 1- December 31, 2021	(1,151,737)	181/365	(571,136)	(1,151,737)	181/365	(571,136)	0	181/365	0
January 1- March 31, 2022	(1,264,812)	91/365	(315,337)	(1,264,812)	91/365	(315,337)	0	91/365	0
April 1- June 30, 2022	(1,264,812)	1/365	(3,465)	(1,264,812)	1/365	(3,465)	0	1/365	0
Pro rata Balance June 30, 2022			$ (1,751,374)			$ (1,751,374)			$ -

KY Jurisdication Factor used for Excess

	Jul 2021	Aug 2021	Sep 2021	Oct 2021	Nov 2021	Dec 2021	Jan 2022	Feb 2022	Mar 2022	Apr 2022	May 2022	Jun 2022
LGE_ECR												
Total Jurisdiction Revenue	106.9	106.3	91.0	80.1	77.4	83.9	88.7	81.5	80.1	75.1	85.1	96.3
ECR Jurisdictional Denominator (less Tracker revenue-add back CSR)	107.2	106.9	91.7	80.2	82.9	90.1	96.0	88.8	86.8	80.1	87.5	97.0
ECR Jurisdictional Factor	99.7%	99.4%	99.2%	100.0%	93.4%	93.1%	92.3%	91.7%	92.2%	93.7%	97.3%	99.3%
ECR Project Depreciation: 2009 plan - Terminating	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ECR Project Depreciation: 2011 plan - Terminating	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6
ECR Project Depreciation: 2016 Plan - Terminating	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0