Michael E. Hornung
Manager, Pricing/Tariffs
State Regulation and Rates
T 502-627-4671 | F 502-627-3213
Mike.hornung@lge-ku.com

a PPL company

VIA ELECTRONIC TARIFF FILING SYSTEM

Ms. Linda Bridwell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601-8294

October 21, 2022

Re: Filing of Special Contract under Kentucky Utilities Company's Economic Development Rider (EDR)
Kruger Packaging (USA), LLC

Dear Ms. Bridwell:

Pursuant to 807 KAR 5:011, Section 13, Kentucky Utilities Company ("KU") P.S.C. No. 20, Original Sheet No. 71, respectfully requests approval of this special contract between KU and Kruger Packaging (USA), LLC. Enclosed for filing are:

- Cover Letter;
- Attachment 1 – Contract for Electric Service;
- Attachment 2 – Special Contract for Economic Development;
- Attachment 3 – State Certification;
- Attachment 4 – Marginal Cost Study; and
- Attachment 5 – Monthly Billing Comparison.

Should you have any questions, please do not hesitate to contact me.

Sincerely,

Michael E. Hornung

KUCES082614

Account Number 3000433499764

CONTRACT FOR ELECTRIC SERVICE

This contract made and entered into this 22 day of October , 2021 by and between Kentucky Utilities Company ("Company") and Kruger Packging ("Customer").

WITNESSETH:

Beginning May 1, 2022 , or as soon thereafter as connection is made, Company will sell and deliver to Customer at 1000 North Black Branch Road, Elizabethtown, KY 42701

all Customer's electric capacity and energy requirements defined as 3 phase, 60 cycle, alternating current, nominal voltage at the point of delivery of 12,470 volts, metered and billed as Secondary service.
Secondary, Primary, Transmission

Customer requires an estimated Contract Capacity of 3,500 kVA or kW, as is appropriate.

Each month Customer will pay to Company for all capacity provided and energy delivered to Customer in the preceding billing period an amount determined in accordance with the

TOD-S Rate Schedule and, as may be appropriate, the
EDR Rider, contract attached if required, and the
____ Rider, contract attached if required, and the
____ Rider, contract attached if required.

Comments: Original contract for service, requesting 3,500kW by May of 2022 expanding to 4,500 by May of 2027, which will require a new contract for service at that time. Customer to be billed under KU's TOD-S tariff with KU's EDR applied.

TARIFF PROVISIONS: It is mutually agreed that Company's terms and conditions and applicable rate schedule, as from time to time approved by and on file with the Public Service Commission of Kentucky, are made a part of this contract as fully as if written here.

IN WITNESS WHEREOF, the parties hereto have caused this contract to be executed by their duly authorized representatives the day and year shown above.

KENTUCKY UTILITIES COMPANY	Kruger Packaging (USA) LLC
By [signature]	By [signature] [signature]
Economic Development Project Manager	JOHN M. KEITH General Manager; Frédéric Boucher VP,Legal Affairs
Official Capacity	Official Capacity

Customer Account 300043349764

SPECIAL CONTRACT
ECONOMIC DEVELOPMENT RIDER

This special contract for Economic Development Rider service ("EDR Contract") is made and entered into this **13th** day of **October, 2022** by and between **Kruger Packaging (USA) LLC.** ("Customer") and Kentucky Utilities Company ("Company").

WITNESSETH:

WHEREAS Company is in the business of providing retail electric service in the Commonwealth of Kentucky.

WHEREAS Customer has applied for and/or is receiving retail electric service from Company pursuant to a Contract for Electric Service dated **10/22/2021** ("Electric Service Contract") under Standard Rate Schedule **KU-TOD-S**; and

WHEREAS Customer requests EDR total Demand Charge discounts on the basis that Customer's proposed monthly billing load ("EDR Contracted Load") meets the requirements outlined in Appendix A for (check appropriate space):

________ Brownfield Development load of ___________ kVA

__X__ Economic Development new load of __3,500__ kVA

________ Economic Development new load of ___________ kVA above an Existing Base Load as defined in the aforementioned Appendix A.

The EDR Total Demand Charge discounts shall be incorporated with the bill for electric service issued pursuant to the Electric Service Contract beginning **October 13, 2022** and will be subject to the same payment provisions as the Electric Service Contract.

NOW, THEREFORE, in consideration of the mutual agreements made herein, the parties agree as follows:

Company's rates, terms, and conditions for the provision of electric service to Customer, and Customer's obligations, rights and responsibilities to the Company for the supply of electric service, are specified in and determined by the Standard Rate Schedule specified above and other applicable schedules, terms, and conditions of service set forth in the Company's tariffs on file with, and approved by, the Kentucky Public Service Commission ("PSC"), and by the terms of the Electric Service Contract. The Company's Rates, Terms and Conditions for Furnishing Electric Service, as filed with and approved by the PSC, both in effect now and in the future, are incorporated by reference and made a part of this EDR Contract as if fully set forth herein.

This EDR Contract is supplemental to, and by agreement made a part of, the Electric Service Contract for the purpose of applying provisions of the Company's Economic Development Rider, Standard Rate Rider EDR ("EDR"), to Customer.

Customer has represented that it anticipates investing $**114,230,777** in its facilities located at [1000 North Black Branch Road, Elizabethtown, KY 42701] (the "EDR Location"), creating approximately **147** new jobs, which economic development will generate the EDR Contracted Load for the Initial Contract Term (as defined below). Therefore, Company hereby agrees to furnish, and Customer agrees to take, EDR service pursuant to the terms and conditions of Standard Rate Rider EDR, as currently approved by the PSC or as may be modified in the future and approved by the PSC.

The initial term of this EDR Contract shall be ten (10) years beginning, at the option of Customer, no later than **12** months following approval of this Special Contract by the PSC (the "Initial Contract Term").

The Total Demand Charge for the twelve (12) consecutive monthly billings and the subsequent four consecutive twelve (12) monthly billing periods, thereafter, shall be reduced by [50%, 40%, 30%, 20%, 10%, respectively] (the "EDR Credits"). All subsequent billing shall be at the full charges stated in the applicable rate schedule after this five (5) year period. Upon termination of the Initial Contract Term, service will continue in accordance with the terms of the Standard Rate Schedule.

In the event that Customer (a) ceases operations at the EDR Location before the Initial Contract Term expires, (b) stops taking service for the EDR Location from Company during the Initial Contract Term, or (c) terminates the EDR Contract before the Initial Contract Term expires (with each of the foregoing being a " Customer Termination Event"), the Customer shall reimburse Company for a portion of the EDR Credits received from the Company by Customer (the "Reimbursement Amount") as set forth hereafter. If a Customer Termination Event occurs during the first two years of the Initial Contract Term, the Customer shall reimburse the Company for 90% of the total EDR Credits received by the Customer. If a Customer Termination Event occurs during the third, fourth or fifth years of the Initial Contract Term, the Customer shall reimburse the Company for 75% of the total EDR Credits received by the Customer. If a Customer Termination Event occurs at any time during the final five years of the Initial Contract Term, the Customer shall reimburse the Company for 50% of the total EDR Credits received by the Customer. The Reimbursement Amount shall be paid to Company by Customer within 30 days of the Customer Termination Event.

Company may terminate this EDR Contract at any time for Customer's failure to comply with the terms and conditions of Standard Rider EDR or this EDR Contract, including but not limited to if Customer ceases operations at the EDR Location, stops taking service during the Initial Contract Term or fails to timely provide the Security (as defined below). Upon termination of the EDR Contract, Company shall be entitled to recover the Reimbursement Amount from Customer and shall be entitled to recover all other damages that it may have at law or in equity, from Customer but with the Reimbursement Amount being the exclusive remedy for EDR Credits previously paid or given to Customer by Company. Such termination will only affect the application of, and Customer's service under, the Standard Rider EDR and this EDR Contract, and shall not affect the application of, or Customer's service under, the Electric Service Contract.

Customer agrees to provide all information necessary to satisfy the PSC initial filing requirements and successive annual reports for the duration of this special contract.

The terms and conditions of this EDR Contract shall inure to and be binding upon the parties, together with their respective successors in interest or assigns, except that Customer may not assign or transfer any of its rights, duties, or obligations hereunder without the prior written consent of Company. An assignment by Customer shall not have any effect whatsoever unless approved in writing by Company in advance of such assignment. Nothing herein shall be construed to confer a benefit on any person not a signatory hereto or the successor to a signatory hereto.

All disputes arising between Customer and Company hereunder shall be finally decided by the PSC in accordance with its applicable rules and procedures. This EDR Contract shall be construed and enforced in accordance with the laws of the Commonwealth of Kentucky.

The failure of either party to enforce or insist upon compliance with any of the terms or conditions of this EDR Contract shall not constitute a waiver or relinquishment of any such terms or conditions.

IN WITNESS WHEREOF, Customer and Company have executed this EDR Contract on the day and year first above written.

Kentucky Utilities Company

By: Will McDonald

Date: October 18, 2022

Customer: Kruger Packaging (USA) LLC

By: ____________________

Date: October 13, 2022

By: ____________________

Date: October 14, 2022

Appendix A

The combined Louisville Gas and Electric Company and Kentucky Utilities Company current, **2022**, capacity reserve margin is **1,348** MW which is **290** MW in excess of a reserve margin considered essential for a system reliability of **1,058** MW. For each year in which Customer will receive demand charge discounts under the EDR Contract, the Company's projected reserve margins are expected to be: Year 1 **1,452** MW, Year 2 **1,472** MW, Year 3 **1,418** MW, Year 4 **1,332** MW, and Year 5 **1,340** MW.

Company estimates investing **$197,949** in new facilities to serve the EDR Contracted Load.

Company estimates Customer's minimum monthly billing under Standard Rate Schedule **KU-TOD-S** will be **$41,208**.

Customer anticipates investing **$114,230,777** in facilities associated with the EDR Contracted Load.

Customer anticipates creating **147** new jobs associated with the EDR Contracted Load.

Customer estimates the EDR Contracted Load to be **3,500** kW or kVA, as is appropriate, at a **74** % load factor.

If the new load is in addition to an existing load, Company and Customer agree that the Existing base Load, in kW or kVA, as is appropriate, is:

January -		Peak,		Intermediate,		Base;
February -		Peak,		Intermediate,		Base;
March -		Peak,		Intermediate,		Base;
April -		Peak,		Intermediate,		Base;
May -		Peak,		Intermediate,		Base;
June -		Peak,		Intermediate,		Base;
July -		Peak,		Intermediate,		Base;
August -		Peak,		Intermediate,		Base;
September -		Peak,		Intermediate,		Base;
October -		Peak,		Intermediate,		Base;
November -		Peak,		Intermediate,		Base; and
December		Peak,		Intermediate,		Base.

Seen and agreed:

Kentucky Utilities Company

By: Will McDowell

Date: October 18, 2022

Customer: ______________________

By: [illegible]

Date: october 13, 2022

By: [illegible]

Date: October 14, 2022

CABINET FOR ECONOMIC DEVELOPMENT

Andy Beshear
Governor

Old Capitol Annex
300 West Broadway
Frankfort, Kentucky 40601

Larry Hayes
Interim Secretary

May 27, 2021

Michael Lafave, Sr. VP
Kruger Packaging (USA) LLC
3285 Bedford Road
Montreal QC H3S1G5

Dear Mr. Lafave:

I am pleased to inform you that the Kentucky Economic Development Finance Authority (KEDFA) preliminarily approved the request from Kruger Packaging (USA) LLC for incentives under the Kentucky Business Investment (KBI) program on May 27, 2021. Please note that the approval is contingent upon receipt of a fully executed Memorandum of Agreement (MOA).

Enclosed are two MOA's to be signed by an official of the company. **Please have both copies signed and returned to our office by June 30, 2021.** Once the MOA's are executed by our office, we will return one original to you for your records.

Preliminary approval is effective for three years, with a progress report required to be submitted on or before the first anniversary of preliminary approval. To finalize your KBI project, we will need evidence of the investments made by the company. Please note preliminary approval does not authorize the company to begin utilizing the KBI benefits of the income tax credit and wage assessment. The benefits may commence only after final approval, the execution of the Tax Incentive Agreement and the activation of the project.

Enclosed is a timeline for the KBI program. Please call me at (502) 782-1986 if you have any questions or require additional information. We appreciate your consideration of Kentucky for this investment and look forward to working with you to finalize this transaction.

Sincerely,

Debra L. Phillips
Incentive Assistance Division

c: Elizabeth Bishop

The Prime Group LLC

Marginal Cost of Service Study

Kentucky Utilities Company
Louisville Gas and Electric Company

August 12, 2022

Table of Contents

Executive Summary

Louisville Gas & Electric Company ("LG&E) and Kentucky Utilities Company ("KU") (collectively "LG&E/KU" or "the Companies") retained The Prime Group, LLC to prepare an estimate of the Companies' marginal cost of providing electric service.

Marginal cost is defined as the change in total cost with respect to a small change in demand (or "output"). In this study, output refers to the total megawatts of capacity or megawatt hours of energy, so that marginal cost is the change in total system cost relative to a small change in total system capacity or energy.

This report describes the methods for estimating marginal production, transmission, and distribution costs for LG&E/KU. For production, the fixed marginal cost and the variable marginal cost are evaluated independently. Results are tabulated herein and in Table ES-1.

Table ES-1.
Louisville Gas & Electric Company and Kentucky Utilities Company
Summary of Marginal Cost of Service

Function	**Marginal Cost of Service**	
	LG&E	**KU**
Production Demand (per KW of Added NCP Demand)	$2.32	$2.32
Production Energy (per KWH of Added Energy)	$0.03447	$0.03447
Transmission (per KW of Added NCP Demand)	$0.06	$0.01

Marginal production demand cost and its calculation are best looked at from the perspective of the electrical system utility planner. The planner begins by developing a schedule of resource additions which allows the utility to meet its forecasted demand obligations. The planner then must address how any incremental demand will be met. Typically, anticipated additional demand is met by taking the existing plan for generation expansion and accelerating it. Based on information from the Companies' 2021 Integrated Resource Plan filed in Kentucky, which indicated that the Companies' next need for generation capacity is 2028, the marginal production demand costs are associated with advancing a Combined Cycle Gas Combustion Turbine from 2028 to 2027 in-service date. The calculation of an Economic Carrying Charge is used to determine the change in cost of advancing this capital asset by one year.

Marginal production energy costs are derived from the Companies' forecasted marginal variable costs for each hour for the twelve months ended December 2023.

Marginal transmission costs are determined using the 2022 Company Business Plan for transmission capacity additions and developing a revenue requirement for those projected capital investments. This projected investment is then divided by the Companies' 12 monthly Coincident Peak demands to determine a Coincident Peak demand rate which is then converted to a rate on a Non-Coincident Peak demand basis based on the Time-of-Day and Retail Transmission Service rate schedules which represent the most likely customers who would be eligible for an Economic Development Rate from the Companies.

Marginal distribution costs are not calculated because the responsibility for such costs are governed by the Line Extension Plan established by KU and LG&E and approved by the Commission in Case Nos. 2020-00349 and 2020-00350 respectively.

This analysis may be utilized to support the commitment made by the Companies in the proceeding, *In The Matter Of: Application Of Louisville Gas And Electric Company And Kentucky Utilities Company To Modify And Rename The Brownfield Development Rider As The Economic Development Rider* in Case No. 2011-00118. In its Order dated August 11, 2011, the Commission noted if the Companies offer special contracts under their Economic Development rate, the Companies will demonstrate with each special contract filing that the discounted rates exceed the marginal cost associated with serving the customer. (Order, page 7.) The marginal cost study presented herein is applicable for such a demonstration.

Introduction

Louisville Gas & Electric Company ("LG&E) and Kentucky Utilities Company ("KU") (collectively "LG&E/KU" or "the Companies") retained The Prime Group, LLC to prepare an estimate of the Companies' typical marginal costs of delivering electricity.

Marginal cost is defined as the change in total cost with respect to a small change in demand, or output. In this report "output" will be used in place of "demand" to avoid confusion with the standard way that the term "demand" is used in the industry to represent the maximum amount of power utilized during any interval over a specified period of time. Therefore, in this study, output refers to the total megawatts of capacity or megawatt hours of energy, so that marginal cost is the change in total system cost relative to a small change in total system capacity or energy.

This report describes the methods for estimating marginal production, transmission, and distribution costs for LG&E/KU. For production, the fixed marginal cost and the variable marginal cost are evaluated independently. The report includes a summary table of the results.

The marginal production demand costs are determined using the resource planning tools that the Companies rely on for development of their Integrated Resource Plan ("IRP"), which is formally prepared every three years and which was most recently filed with the Kentucky Public Service Commission ("the Commission") on October 19 2021, in Case No. 2021-00393. The Companies expect to need additional generation capacity in 2028 due to the retirement of Brown 3 and Mill Creek 2 for environmental requirements.

The study is also based on data from the Companies' official books and records as reflected on the Form 1 filings with the Federal Energy Regulatory Commission ("FERC"). Form 1 data utilized includes system peak demand data (in MW) and transmission and distribution cost data (in $) by FERC account. Cost escalation factors were determined using the Consumer Price Index ("CPI") data from the U.S. Department of Labor Bureau of Labor Statistics and/or the Handy-Whitman Index of Public Utility Construction Costs ("Handy-Whitman Index"), as appropriate for the particular type of cost to be escalated.

Marginal costs have several applications. In most jurisdictions in the U.S., the most common application of marginal cost studies by utilities is for designing economic development or other incentive rates. Similarly, the marginal costs are also utilized for analyzing discounted rates provided to certain customers pursuant to special contracts. Another application is for the development of particular components of other rate offerings, e.g. determining rate differentials for use in time-differentiated rates, such as time-of-use or critical-peak-pricing rate schedules.

In particular for LG&E and KU, this analysis may be utilized to support the commitment made by the Companies in *In The Matter Of: Application Of Louisville Gas And Electric Company And Kentucky Utilities Company To Modify And Rename The Brownfield Development Rider As The Economic Development Rider* in Case No. 2011-00118. In its Order dated August 11, 2011, the Commission noted if the Companies offer special contracts under their Economic Development rate, the Companies will demonstrate with each special contract filing that the discounted rates exceed the marginal cost associated with serving the customer. (Order, page 7.) The marginal cost data presented herein, or in subsequent studies, is applicable for such a demonstration.

Marginal Cost Theory

Marginal cost is defined as the change in total cost with respect to a change in output of one unit. Mathematically, marginal cost can be represented as the partial derivative of total cost to output, and can be stated as follows:

$$MC = \frac{\partial C}{\partial q}$$

where

MC	=	Marginal Cost
∂C	=	Change in Total Cost
∂q	=	Change in Output

In the context of discrete cost and output, marginal cost can be *estimated* as follows:

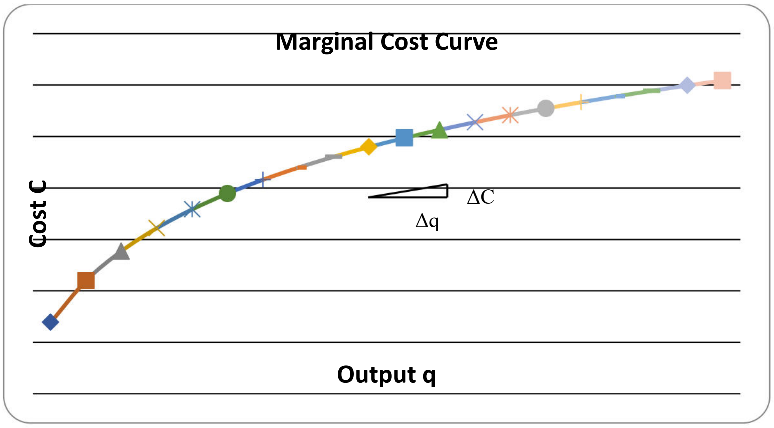
$$MC = \frac{\Delta C}{\Delta q}$$

where

MC	=	Marginal Cost
ΔC	=	Change in Total Cost
Δq	=	Change in Output

Graphically, the marginal cost is the slope of the line resulting from the graph of the total cost C and the total output q, as shown in Figure 1.

Figure 1. Cost vs. Output Curve



In the figure, "output" refers to total megawatts of capacity or megawatt hours of energy required, so that marginal cost is the change in total system cost relative to a small change in total system output.

Marginal Production Demand Cost

The marginal demand costs for production are the changes in capacity costs associated with serving changes in demand on the electric system.

Recall that marginal cost is broadly defined as the change in total cost with respect to a small change in output. In this instance, the "output" refers to total megawatts of generating capacity required, so that marginal cost is the change in total system capacity cost relative to a small change in total system demand.

Marginal production demand cost and its calculation is best looked at from the perspective of the electrical system utility planner. The planner begins by developing a schedule of resource acquisitions which allows the utility to meet its forecasted demand obligations. The planner then must address how any incremental demand will be met. Typically, anticipated additional demand is met by taking the existing plan for generation expansion and accelerating it.[1]

To evaluate the change in capacity costs, a base case is defined that specifies the capacity (and associated capacity cost) required to meet the Companies' base demand forecast for the planning period. Other scenarios are then developed in which the total system demand is increased by set increments, and the capacity acquisitions required to meet those incremental demands are determined. The net present value of the capacity costs in the base case would then be compared to the net present value of the capacity costs for the incremental cases to determine the change in

[1] Charles J. Cicchetti, et al, *The Marginal Cost and Pricing of Electricity: An Applied Approach* (Cambridge, MA: Ballinger Publishing Co., 1977), 8.

capacity cost associated with the change in total system demand. A more detailed description of the computation is shown in Attachment A.

The base case is based on the Companies' 2021 Integrated Resource Plan which indicates that the Companies will need new capacity in 2028 due to the retirement of the Brown 3 and Mill Creek 2 units. In addition, Ford Motor Company recently announced the siting of a 320MW electric vehicle battery facility in the Companies' service territory. Upon announcement, the Companies evaluated this additional load and determined that it did not accelerate the need for generating capacity sooner than 2028. Therefore, this analysis assumes that the next need date for capacity for the Companies remains in 2028 following the announced plant retirements.

The plan includes both supply-side and demand-side resources, but for this assessment only the supply-side resources are considered. To estimate marginal production capacity costs, The Prime Group considered the case wherein new load additions by 2027 would equal 100 MWs, which would require the Companies to build or purchase new capacity to maintain the desired 17% Reserve Margin Requirement (RMR).[2] The Resource Assessment is summarized in Table 1.

Another way to consider this approach is to consider a stable system (the base case). The initial condition is then perturbed (by a small increase in system demand), and equilibrium is re-established (by adjustments to the resource acquisition plan). This process is repeated for several incremental perturbations (i.e. by incremental increases to system demand in blocks of say 25 MW). The cost of the stable base case are then compared to the costs of the stable incremental cases to determine the marginal cost (at whatever increment first requires a change to the resource acquisition plan).

The timing of the generation additions needed to meet demand obligations in each year of the planning period for all of the scenarios are determined by the detailed resource planning models compiled in SAS, R, and Metrix ND with @Risk used to assess the reasonableness of the forecasts which the Companies routinely use in the IRP and in other generation planning and forecast evaluations. The capacity costs associated with the supply resource additions listed are included in the IRP.

[2] Because resource additions are outside the planning horizon, marginal production capacity costs determined based on the assumed addition of 85 MW of load should be considered a maximum anticipated level of marginal costs.

Table 1.
2021 Resource Assessment

Year	Resource
2022	
2023	
2024	Retirement of Mill Creek 1 (300 MW)
2025	Retirement of Haefling 1-2 (24MW) and Paddy's Run 12 (23 MW)
2026	
2027	
2028	Retirement of Mill Creek 2 (297MW) and Brown 3 (412MW)
2029	
2030	
2031	
2032	
2033	
2034	Retirement of Ghent 1 (475MW)/Ghent 2 (485MW)/Brown 9 (121MW)
2035	Retirement of Brown 8 and 10 (121MW x 2)
2036	Retirement of Brown 11 (121MW)

Notes:

- Unit ratings for new units and retirements are summer net ratings.

The cases and the impacts on the resource plan are summarized in Table 2.

Table 2.
Case Summary for Marginal Cost Evaluation

Case	Incremental Demand	Change to Resource Acquisition Plan?
Base	n/a	n/a
Case 1	25 MW	No
Case 2	50 MW	No
Case 3	75 MW	No
Case 4	100 MW	Yes

Increasing the total system demand by 100 MW, requires that the resource acquisition plan in the IRP be revised in order to meet the incremental demand obligations. The acquisition of a Combined Cycle gas combustion turbine must be advanced from 2028 to 2027 in order to meet the incremental 100 MW obligation. This change is highlighted in Table 3. (Other portions of the plan that do not differ, including all of the demand-side options, are not included for the sake of simplicity.)

Table 3.
Change in Resource Plan for Incremental 75 to 100 MW Demand

Year	Base Case	+75 MW Case to +100 MW Case
2027		Combined Cycle Gas Combustion Turbine
2028	Combined Cycle Gas Combustion Turbine	

To determine the change in capacity costs associated with the advancement of Combined Cycle gas combustion turbine from 2028 to 2027, the *Economic Carrying Charge* is calculated. The Economic Carrying Charge is the economic cost of advancing or delaying the present value of revenue requirements associated with capital expenditures. This computation is described in Attachment A.

The marginal production demand cost is the monthly value of the Economic Carrying Charge Rate ("ECRR") applied to the present value revenue requirement ("PVRR") of the capital asset. The computation of both the PVRR of the capital asset and the Economic Carrying Charges are provided in Attachment B. Because the fixed O&M expenses were negligible in comparison to the asset costs, they were not included in the analysis.

Based on the computations included in Attachments A and B, the marginal production demand cost on a Coincident Peak ("CP") basis is $3.84 per month. Using an average coincidence factor from KU and LG&E's large power classes of customers from the last Companies' last retail rate cases, the CP marginal cost value is converted to a Non-Coincident Peak ("NCP") marginal cost value of $2.32 per month. Because the LG&E and KU generating units are jointly operated and dispatched to meet the combined demands of the LG&E and KU systems, a single value is provided for the marginal production demand cost on a joint Company basis. For evaluating an economic development offer, it would be necessary to adjust the NCP marginal cost value to reflect the applicable loss-factor for a prospective customer which could take service at a transmission, primary or secondary voltage.

Marginal Production Energy Cost

The marginal production energy cost is derived from the forecasted twelve months of variable production cost data for the LG&E/KU combined system. Specifically, the Company provided data for the twelve months ended December 2023 pertaining to the marginal costs for fuel, consumables (including scrubber reactants and other reagents), ash and waste disposal, and emission allowances for all 8,760 hours based on each hour's marginal generating unit for the next

MW of capacity needed on the system. The marginal generation unit's variable cost for each hour of the corresponding twelve months was then used to calculate a total average variable cost, for the combined LG&E and KU system. This computation is described in Attachment C. Because the preponderance of LG&E and KU's generating assets are base-load resources, average marginal energy costs will not differ materially from average energy costs on an annual basis.

The marginal production energy cost per kWh of additional energy for both LG&E and KU is $0.03447. In addition, it would be necessary to adjust the marginal energy cost value to reflect the applicable loss-factor for a prospective customer which could take service at a transmission, primary or secondary voltage.

Marginal Transmission Cost

The marginal transmission cost is calculated using the Economic Carrying Charge approach outlined above, but with different source data. The general approach of applying an ECRR to the PVRR of the capital asset is followed; however, in the case of transmission, the capital asset is not a new generating unit but instead represents the value of additional transmission plant.
Recall that marginal costs are defined as the change in total cost with respect to a small change in output. For discrete costs and output, the formula is:

$$MC = \frac{\Delta C}{\Delta q}$$

where

MC	=	Marginal Transmission Cost
ΔC	=	Change in Total Cost of Transmission Plant
Δq	=	Change in system demand

The Prime Group evaluated the capital cost of transmission forecast due to capacity additions based on the Companies' 2022 Business Plan which run from 2023 through 2032. An analysis was performed based on the Companies' current capital structure to determine a PVRR for these forecasted transmission additions. This PVRR was then divided by each of the Companies 12-month Coincident Peak Demands during their most recent rate cases to determine a rate per CP-kW for transmission. This rate was then adjusted using the average coincidence factors of the Companies' large power customers to determine a rate on an NCP basis similar to the Production Demand costs discussed earlier. This computation is shown in Attachment D.

For KU, the marginal transmission cost per KW of additional NCP demand is $0.01. For LG&E, the marginal transmission cost per KW of additional NCP demand is also $0.06. Again, it would be necessary to adjust the marginal transmission cost value to reflect the applicable loss-factor for a prospective customer which could take service at a transmission, primary or secondary voltage.

Marginal Distribution Cost

The marginal distribution cost for KU and LG&E in theory could be calculated using the same approach as the marginal transmission costs. However, from a ratemaking and policy standpoint, distribution and transmission differ. For distribution, the Companies established a Line Extension Plan, most recently approved on June 30, 2021, by the Commission for KU and LG&E in Case Nos. 2020-00349 and 2020-00350 respectively. The Line Extension Plan is applicable in all service territory where the Companies do not have existing facilities to meet the electric service needs of its retail customers. The plan specifies how the costs for normal line extensions and other line extensions will be handled. This practice makes moot the determination of a marginal distribution cost for the system at large because any individual facility addition, and its particular costs, will be considered on an actual-cost and specific-customer basis, pursuant to the Line Extension Plan.

Summary

The marginal costs for KU and LG&E for Production Demand, Production Energy, and Transmission are summarized in Table 4.

Table 4.
Louisville Gas & Electric Company and Kentucky Utilities Company
Summary of Marginal Cost of Service

Function	**Marginal Cost of Service**	
	LG&E	**KU**
Production Demand (per KW of Added NCP Demand)	$2.32	$2.32
Production Energy (per KWH of Added Energy)	$0.03447	$0.03447
Transmission (per KW of Added NCP Demand)	$0.06	$0.01

Attachments

Computation of the
Economic Carrying Charges
Associated With Delaying a Planned Generating Resource
by a Fixed Number of Years

Economic carrying charges are the economic costs of advancing (moving forward) or delaying (moving backwards) the present value revenue requirements associated with a capital expenditure. In other words, an economic carrying charge is a measurement of the effect on a utility's present value revenue requirements (PVRR) of advancing or delaying the installation of a utility resource. For example, if an increase in load causes a generating resource to be moved forward *a* years, the economic carrying charges measures the effect on PVRR of moving the resource forward *m* years. Economic carrying charges are often calculated assuming a=1 (i.e., moving the resource forward one year).

Where:

ECC = Economic Carrying Charges

ECCR = Economic Carrying Charge Rate

PVRR = Present value revenue requirement for the asset in current dollars.

g = Annual Inflation Rate

r = Adjusted Weighted Cost of Capital

L = Life of the asset

i = index factor representing every L years

a = the number of years that the asset is advanced

m = the number of years prior to when the asset is installed after taking into consideration the number of years *a* that the asset is advanced, necessary to reflect the carrying charge rate in current year dollars.

$$ECC = \frac{(1+g)^m}{(1+r)^m}\left[\sum_{i=0}^{\infty} PVRR\ \frac{(1+g)^{Li}}{(1+r)^{Li}} - \frac{(1+g)^a}{(1+r)^a}\sum_{i=0}^{\infty} PVRR\,\frac{(1+g)^{Li}}{(1+r)^{Li}}\right]$$

$$= \frac{(1+g)^m}{(1+r)^m}\left[PVRR\left\{\sum_{i=0}^{\infty}\frac{(1+g)^{Li}}{(1+r)^{Li}} - \frac{(1+g)^a}{(1+r)^a}\sum_{i=0}^{\infty}\frac{(1+g)^{Li}}{(1+r)^{Li}}\right\}\right]$$

$$= \frac{(1+g)^m}{(1+r)^m}\left[PVRR\left\{\left(1-\frac{(1+g)^a}{(1+r)^a}\right)\sum_{i=0}^{\infty}\frac{(1+g)^{Li}}{(1+r)^{Li}}\right\}\right]$$

$$= \frac{(1+g)^m}{(1+r)^m}\left[PVRR\left\{\left(1-\frac{(1+g)^a}{(1+r)^a}\right)\sum_{i=0}^{\infty}\left(\frac{(1+g)^L}{(1+r)^L}\right)^i\right\}\right]$$

$$= PVRR\,\frac{(1+g)^m}{(1+r)^m}\left[\left(1-\frac{(1+g)^a}{(1+r)^a}\right)\left[\frac{1}{1-\frac{(1+g)^L}{(1+r)^L}}\right]\right]$$

The last step in the above derivation converts a infinite geometric series to a fixed value. Mathematically, a geometric series converges to the following value as long as $0 \le x \le 1$:

$$\sum_{i=0}^{\infty} x^i = \frac{1}{1-x}$$

(See, for example, Walter Rudin, *Principles of Mathematical Analysis* (McGraw-Hill, Inc.; 1976) at 61.) In the context of an economic carrying charge, the infinite series shown in the penultimate line of the above derivation will converge to a known value as long as $g < r$.

The Economic Carrying Charges (ECC) can also be calculated by multiplying the PVRR by an Economic Carrying Charge Rate (ECCR) (i.e. ECC = PVRR x ECCR), where the ECCR is calculated as follows:

$$ECCR = \frac{(1+g)^m}{(1+r)^m}\left[\left(1-\frac{(1+g)^a}{(1+r)^a}\right)\left[\frac{1}{1-\frac{(1+g)^L}{(1+r)^L}}\right]\right]$$

Louisville Gas & Electric and Kentucky Utilities
Economic Carrying Charge of CCGT Addition

Assumptions	Values
Inflation Rate (g)	2.50%
Weighted Cost of Capital (r)	6.41%
Year Scheduled to be Installed	2028
Year Installed After Load Addition	2027
a	1
Current Year	2022
m	5
PVRR	1175.20
Service Life (L)	40
Economic Carrying Charge Rate (ECRR)	3.93%
Coincidence Factor	60.27%

Annual Value (CP) =	**$**	**46.13**
Annual Value (NCP) =	**$**	**27.80**
Monthly Value (CP) =	**$**	**3.84**
Monthly Value (NCP) =	**$**	**2.32**

$$ECCR = \frac{(1+g)^m}{(1+r)^m}\left[\left(1-\frac{(1+g)^a}{(1+r)^a}\right)\left[\frac{1}{1-\frac{(1+g)^L}{(1+r)^L}}\right]\right]$$

Louisville Gas & Electric and Kentucky Utilities
Present Value Revenue Requirement Analysis
New CCGT Addition

Assumptions:

Investment	951.00
Book Life	40
Tax Life	20
Composite Tax Rate	24.8405%
Property Tax Rate	0.74%
Levelized Revenue Requirement Years	40

Results:

Present Value Revenue Requirement	$	1,175
Levelized Revenue Requirement	$	87
Levelized Carrying Charge Rate		9.13%

Year	Investment	Book Depreciation	Net Plant	Tax Depreciation	Residual Plant	Deferred Income Tax	Accumulated Deferred Income Tax
0	$ 951						
1		$ 24	$ 927	$ 36	$ 915	$ 3	$ 3
2		24	903	69	847	11	14
3		24	880	63	783	10	24
4		24	856	59	724	9	33
5		24	832	54	670	8	40
6		24	808	50	620	7	47
7		24	785	46	573	6	52
8		24	761	43	530	5	57
9		24	737	42	488	5	62
10		24	713	42	446	5	67
11		24	689	42	403	5	71
12		24	666	42	361	5	76
13		24	642	42	318	5	80
14		24	618	42	276	5	85
15		24	594	42	233	5	90
16		24	571	42	191	5	94
17		24	547	42	148	5	99
18		24	523	42	106	5	104
19		24	499	42	64	5	108
20		24	476	42	21	5	113
21		24	452	21	(0)	(1)	112
22		24	428	-	(0)	(6)	106
23		24	404	-	(0)	(6)	100
24		24	380	-	(0)	(6)	94
25		24	357	-	(0)	(6)	89
26		24	333	-	(0)	(6)	83
27		24	309	-	(0)	(6)	77
28		24	285	-	(0)	(6)	71
29		24	262	-	(0)	(6)	65
30		24	238	-	(0)	(6)	59
31		24	214	-	(0)	(6)	53
32		24	190	-	(0)	(6)	47
33		24	166	-	(0)	(6)	41
34		24	143	-	(0)	(6)	35
35		24	119	-	(0)	(6)	30
36		24	95	-	(0)	(6)	24
37		24	71	-	(0)	(6)	18
38		24	48	-	(0)	(6)	12
39		24	24	-	(0)	(6)	6
40		24	0	-	(0)	(6)	0

Louisville Gas & Electric and Kentucky Utilities
Present Value Revenue Requirement Analysis
New CCGT Addition

Assumptions:

Investment	$	951
Book Life		40
Tax Life		20
Composite Tax Rate		24.8405%
Property Tax Rate		0.74%
Levelized Revenue Requirement Years		40

Results:

Present Value Revenue Requirement	$	1,175
Levelized Revenue Requirement	$	87
Levelized Carrying Charge Rate		9.13%

Year	Rate Base	Interest	Equity	Property Taxes	Income Taxes	Annual Rev Requirement	Present Value Interest Factor	Present Value Revenue Requirement
0							1.000000	$ -
1	$ 924	$ 0	$ 63	$ 7	$ 21	$ 115	0.939758	108
2	889	0	61	7	20	112	0.883146	99
3	856	0	59	6	19	108	0.829944	90
4	823	0	57	6	19	105	0.779947	82
5	792	0	54	6	18	102	0.732961	75
6	762	0	52	6	17	99	0.688807	68
7	732	0	50	6	17	96	0.647312	62
8	704	0	48	6	16	94	0.608317	57
9	675	0	46	5	15	91	0.571671	52
10	647	0	44	5	15	88	0.537233	47
11	618	0	42	5	14	85	0.504869	43
12	590	0	40	5	13	83	0.474455	39
13	562	0	39	5	13	80	0.445873	36
14	533	0	37	5	12	77	0.419013	32
15	505	0	35	4	11	74	0.393771	29
16	476	0	33	4	11	72	0.370049	26
17	448	0	31	4	10	69	0.347757	24
18	419	0	29	4	10	66	0.326808	22
19	391	0	27	4	9	63	0.307120	19
20	363	0	25	4	8	60	0.288619	17
21	340	0	23	3	8	58	0.271232	16
22	322	0	22	3	7	56	0.254893	14
23	304	0	21	3	7	55	0.239537	13
24	286	0	20	3	6	53	0.225107	12
25	268	0	18	3	6	51	0.211546	11
26	250	0	17	2	6	49	0.198803	10
27	232	0	16	2	5	47	0.186826	9
28	214	0	15	2	5	45	0.175572	8
29	197	0	13	2	4	44	0.164995	7
30	179	0	12	2	4	42	0.155055	6
31	214	0	15	2	5	45	0.145715	7
32	190	0	13	1	4	43	0.136937	6
33	166	0	11	1	4	40	0.128687	5
34	143	0	10	1	3	38	0.120935	5
35	119	0	8	1	3	36	0.113650	4
36	95	0	7	1	2	33	0.106803	4
37	71	0	5	1	2	31	0.100369	3
38	48	0	3	0	1	28	0.094323	3
39	24	0	2	0	1	26	0.088641	2
40	0	0	0	0	0	24	0.083301	2

Net Present Value Revenue Requirement $ 1,175

Louisville Gas & Electric and Kentucky Utilities
Present Value Revenue Requirement Analysis
New CCGT Addition

Assumptions:

Investment	$ 951
Book Life	40
Tax Life	20
Composite Tax Rate	24.8405%
Property Tax Rate	0.74%
Levelized Revenue Requirement Years	40

Results:

Present Value Revenue Requirement	$ 1,175
Levelized Revenue Requirement	$ 87
Levelized Carrying Charge Rate	9.13%

Year	Cumulative Present Value Revenue Requirement	Annual Carrying Charge Rate
0	$ -	
1	108	12.10%
2	207	11.75%
3	297	11.41%
4	379	11.08%
5	454	10.76%
6	522	10.45%
7	585	10.14%
8	642	9.85%
9	694	9.56%
10	741	9.27%
11	784	8.98%
12	823	8.69%
13	859	8.39%
14	891	8.10%
15	921	7.81%
16	947	7.52%
17	971	7.23%
18	992	6.94%
19	1,012	6.65%
20	1,029	6.35%
21	1,045	6.11%
22	1,059	5.92%
23	1,073	5.73%
24	1,084	5.54%
25	1,095	5.35%
26	1,105	5.16%
27	1,114	4.97%
28	1,122	4.78%
29	1,129	4.59%
30	1,135	4.40%
31	1,142	4.72%
32	1,148	4.48%
33	1,153	4.23%
34	1,158	3.98%
35	1,162	3.73%
36	1,165	3.49%
37	1,168	3.24%
38	1,171	2.99%
39	1,173	2.75%
40	1,175	2.50%

Louisville Gas and Electric and Kentucky Utilities
Weighted Cost of Capital and MACRS

Capital Structure:

	Percent	Rate	Weighted COC	Tax Rate	Adjusted Rate
Short Term Debt	1.52%	0.46%	0.01%	24.84%	0.01%
Long Term Debt	45.26%	4.08%	1.85%	24.84%	1.39%
Common Equity	53.22%	9.43%	5.02%		5.02%
			6.87%		6.41%

Tax Depreciation Table (MACRS)

	5		15	20
1	20.000%	10.000%	5.000%	3.750%
2	32.000%	18.000%	9.500%	7.219%
3	19.200%	14.400%	8.550%	6.677%
4	11.520%	11.520%	7.700%	6.177%
5	11.520%	9.220%	6.930%	5.713%
6	0.000%	7.370%	6.230%	5.285%
7	0.000%	6.550%	5.900%	4.888%
8	0.000%	6.550%	5.900%	4.522%
9	0.000%	6.560%	5.910%	4.462%
10	0.000%	6.550%	5.900%	4.461%
11	0.000%	0.000%	5.910%	4.462%
12	0.000%	0.000%	5.900%	4.461%
13	0.000%	0.000%	5.910%	4.462%
14	0.000%	0.000%	5.900%	4.461%
15	0.000%	0.000%	5.910%	4.462%
16	0.000%	0.000%	2.950%	4.461%
17	0.000%	0.000%	0.000%	4.462%
18	0.000%	0.000%	0.000%	4.461%
19	0.000%	0.000%	0.000%	4.462%
20	0.000%	0.000%	0.000%	4.461%
21	0.000%	0.000%	0.000%	2.231%
22	0.000%	0.000%	0.000%	0.000%
23	0.000%	0.000%	0.000%	0.000%
24	0.000%	0.000%	0.000%	0.000%
25	0.000%	0.000%	0.000%	0.000%
26	0.000%	0.000%	0.000%	0.000%
27	0.000%	0.000%	0.000%	0.000%
28	0.000%	0.000%	0.000%	0.000%
29	0.000%	0.000%	0.000%	0.000%
30	0.000%	0.000%	0.000%	0.000%

Average Marginal Variable Costs
12 Months ending December 2023 (Forecasted)

Month	Average Marginal Cost ($/MWh)
January	35.83
February	35.54
March	35.43
April	35.78
May	32.74
June	33.45
July	34.03
August	34.09
September	33.59
October	34.67
November	33.90
December	34.64
Average	**34.47**

Capacity-Related Transmission Investment
2022 Business Plan
($ in Thousands)

Year		KU		LG&E	Total
2023		3,552		4,235	7,787
2024		52		867	919
2025		749		1,791	2,540
2026		-		904	904
2027		236		-	236
2028		92		1,229	1,321
2029		995		3,367	4,362
2030		60		3,618	3,678
2031		1,251		-	1,251
2032		-		-	-
10-Year Total		6,987		16,011	22,998
Carrying Cost Percentage		12.65%		13.90%	
Annualized Avoided Costs (in $)		$883,622		$2,224,978	
Forecasted LGE Total System Demand				23,513,673	
Forecasted KU Total System Demand		37,037,501			
Cost per CP kW	$	0.02	$	0.09	
Coincidence Factor		61.26%		59.27%	
Cost per NCP kW	$	0.01	$	0.06	

Comparison of KU Standard Time-of-Day Secondary Rate with Economic Development Rider to Marginal Cost

		Five Year Average Discount	Discounted Rate		
KU TODS					
Basic Service Charge	$ 222.80		$222.80		
Energy Charge	$ 0.02862		$0.02862	Energy	$0.03447
Demand Charge				Demand	
Peak Period	$ 8.28	30%	$5.80	Production	$2.32
Intermediate Period	$ 6.66	30%	$4.66	Transmission	$0.01
Base Period	$ 3.25	30%	$2.28		
	$ 18.19		$12.74		$2.33

Year 1 Billing Comparison

	Billing Units	Currrent KU TODS	Base Rate Billing	EDR Year 1 Discount	Base Rate Plus EDR Billing		Marginal Rate	Marginal Rate Billing
Basic Service Charge		$222.80						
Energy Charge *	1,890,700	$0.02862	$54,111.83		$54,111.83	Energy	$0.03447	$65,172.43
Demand Charge						Demand		
Peak Period	3,500	$8.28	$28,980.00			Production	$2.32	$8,120.00
Intermediate Period	3,500	$6.66	$23,310.00			Transmission	$0.01	$35.00
Base Period	3,500	$3.25	$11,375.00					
			$63,665.00	-50%	$31,832.50			
			$117,776.83		$85,944.33			$73,327.43

* Energy based on an average month with 730 hours and a 74.0% load factor