2023 Electric Revenue Requirements, Cost of Service and Rate Design

Kansas City Board of Public Utilities

KCBPU 2023 Rate Study
Project No. 148283

Rate Hearing Final Draft
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1.0 EXECUTIVE SUMMARY

This report presents the results of a comprehensive electric rate study (Study) prepared for the Kansas City Board of Public Utilities (BPU) by 1898 & Co., a division of Burns & McDonnell Engineering Company, Inc. (1898 & Co.). The BPU owns and operates the electric power generation, transmission, and distribution system serving customers located within, and areas outside the City of Kansas City, Kansas. This Study is for the forecasted period of operations through 2027. With guidance from the BPU staff, our recommendations reflect the following primary considerations: (1) fund the electric utility on a self-supporting basis; (2) phase-in the impact of rate adjustments to the utility; and (3) build to and maintain appropriate cash reserve funds and debt service coverage.

As a first step in the rate study process, BPU asked 1898 & Co. to review its Financial Policies document and make recommendations for modifications to improve transparency and align better with industry peers and rating agency expectations. The primary outcome of that review is the creation of two new reserve funds that will be used to track BPU's minimum cash reserve levels, measured in days cash on hand at the end of each year. The two funds will be an O&M Reserve Fund and an ERC Reserve Fund. Both funds will have a target of 120 days of annual expenses, with the newly established ERC reserve fund being gradually funded to the 120 day target by 2027. When combined, the electric utility will have a combined 120 days of operating expense held in reserve. The O&M Reserve Fund will be built up and maintained with base rates and the ERC Reserve will be built up and maintained through the ERC rider. Debt service coverage recommendations remain the same.

1.1 Study Objectives

The objectives of the rate study are as follows:

1. Forecast the electric utility revenues and revenue requirements for periods 2023 – 2027 to determine the overall adequacy of existing rates to support the utility's operating and capital needs while building prudent cash reserves over the five-year period.
2. Prepare an unbundled class cost of service analysis for the electric utility to identify equitable revenue levels for each rate class.
3. Recommend revised rates and rate schedules that reflect cost of service considerations, meet BPU goals, and practical rate implementation constraints.

1.2 Utility Financial Operations Under Existing Rates

Consistent with BPU's planning and budgeting process, 1898 & Co. uses the cash basis of determining annual revenue requirements as a guide in recommending overall rate adjustments. The cash basis is an accepted industry norm for municipal utility rate and bond financing studies and is used by the BPU to forecast financial operations.

Electric utility rate revenues under existing rates, including riders but excluding PILOT[1], are forecast to increase from $253.2 million in 2023 to $259.5 million in 2027, representing approximately an average $1.3 million annual increase in revenues. Of that amount, the revenue

[1] PILOT – Payment in Lieu of Taxes

forecast to be recovered in base rates increases from $148.2 million in 2023 to $153.3 million in 2027, an average of approximately $1.0 million per year.

1.3 Revenue Requirements

Operation and Maintenance (O&M) expenses in the forecast period are based on the 2023 budget provided by the BPU. These are escalated over the forecast period based on the BPU's projected increases in costs.

The 5-Year Capital Improvement Plan (CIP) is based on the 2023 budget, which provides a forecast of projects through 2027, and has been reviewed and updated by BPU management. The CIP will be funded with annual operating revenues where surplus cash funds are available. The non-cash financing of the CIP will be from revenue bonds.

Debt financing a portion of major capital expenditures is recommended to a) reduce rate impact on current customers, b) recover these capital dollars, over time, from the future customers who will benefit from these investments in the electric system, and c) build and maintain operating cash reserves. 1898 & Co. worked collaboratively with BPU to find a preferred mix of cash and debt financing, which resulted in recommending a $50 million revenue bond issue in 2023, which has been included in the projections for the study period.

Other revenue requirements include the portion of the CIP that is funded with annual operating revenues (cash financed), PILOT payments, and other utility programs such as heat pump rebates and economic development program costs.

1.4 Forecast Financial Metrics Under Existing Rates

Total cash revenue requirements consist of O&M expenses, funding obligations, debt service, capital expenditures, and PILOT transfers to the Unified Government of Wyandotte County and Kansas City, Kansas (UG). Under existing rates, annual revenue deficits will cause the BPU to draw down cash reserve fund balances and reduce the utility's ability to adequately fund and implement the CIP. Safe, reliable, and cost effective utility service requires that the BPU maintain reasonable financial metrics related to debt service coverage, cash reserves, and the ability to fund a portion of the CIP. As shown in Table 1-1 below, under existing rates and projected revenue requirements, the forecast shows a negative annual operating deficit beginning in 2024 and a steady decline in cash throughout the study period.

Table 1-1: Financial Metrics Under Existing Rates

Financial Metrics Under Existing Rates						
Description	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Revenue Surplus / (Deficiency) Under Existing Rates	$ 12,930,453	$ 786,157	$ (835,770)	$ (1,075,671)	$ (12,937,820)	$ (11,855,808)
Operating Cash Balance						
Beg Balance	$ 25,619,100	$ 38,549,553	$ 39,335,710	$ 38,499,941	$ 37,424,270	$ 24,486,449
Annual Cash Flow	$ 12,930,453	$ 786,157	$ (835,770)	$ (1,075,671)	$ (12,937,820)	$ (11,855,808)
End Balance	$ 38,549,553	$ 39,335,710	$ 38,499,941	$ 37,424,270	$ 24,486,449	$ 12,630,642
Days of O&M Reserved	**82**	**74**	**76**	**72**	**47**	**24**
Target Minimum Days Cash	90	120	120	120	120	120
Annual Debt Service Coverage without PILOT Revenue						
Total System Achieved (Total Debt)	**1.85**	**1.61**	**1.48**	**1.47**	**1.54**	**1.53**
Target Minimum Coverage	1.60	1.60	1.60	1.60	1.60	1.60

1.5 Recommended Base Rate Adjustments

Based on the financial forecast under existing rates for the period 2023 through 2027, 1898 & Co. recommends a series of two 2.5% increases to base rate revenue, effective in July 2023 and July 2024.

Table 1-2: Recommended Base Rate Adjustments

Description	2023	2024
Recommended Base Rate Increase	2.5%	2.5%
Date of Increase	July 1, 2023	July 1, 2024

1.5.1 Recommended Changes to Financial Policies

In addition to the recommended base rate increases, we recommend the electric utility begin gradually funding the newly created ERC Reserve fund over a period of five years to gradually reach the 120 days of annual ERC expenditures policy. This equates to recovering an additional $1.5 million per quarter through 2027 to build to the ERC reserve target of approximately $27 million. If the ERC reserve fund was not funded as planned, additional base rate increases would be required to reach the same overall operating reserve target. The new O&M Reserve fund will be funded through base rates and includes all cash currently considered unrestricted for the purposes of calculating days cash on hand. The base rate increases proposed covers both the increases in operating costs and debt service payments, plus building to and maintaining a minimum of 120 days of O&M expenses.

1.6 Forecasted Financials Under Recommended Adjustments

There are many interrelated issues that can lead to the need for rate increases. The most common include inflationary increases to operating costs, issuance of new debt, loss of customer load, maintaining adequate debt service coverage, and maintaining healthy operating reserves. Included in the BPU's financial policy is a requirement that net revenue for the electric utility should be equal to 160 percent of annual debt service payments, excluding PILOT revenue. With recommendations from 1898 & Co., the BPU has set a goal of increasing operating reserves to 120 days of cash on hand, which is a key driver in this rate case, along with increasing the amount of fixed purchased power capacity payments recovered in base rates from $2.6 million to $4.6 million. The latter has a net zero impact on customer's total bills as the amount of purchased power costs recovered in the Energy Rate Component (ERC) is reduced by $2.0 million.

The recommended adjustments result in a cumulative base revenue increase of $30.4 million over five years, through the 2023 - 2027 study period. These increases assist the BPU in meeting target financial metrics for debt service coverage and operating reserves. The BPU management team is committed to managing its costs and strengthening financial metrics during this period in order to align with rating agency target financial metrics that are expected to maintain the BPU's current credit rating.

The recommended adjustments result in positive annual cash flow through the end of the study period. Total debt service coverage under these recommendations builds up to 1.85 in 2027. The number of days operating cash on hand builds up from 84 days in 2023 to 132 days in 2027, meeting the 120 day target by 2025. These results include the two recommended 2.5% base rate increases effective in 2023 and 2024, a recommended bond issuance of $50 million in 2023, and the creation and funding of the ERC Reserve.

Table 1-3: Key Financial Metrics Under Proposed Rates

Financial Metrics Under Proposed Rates						
Description	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Revenue Surplus / (Deficiency) Under Existing Rates	$ 12,930,453	$ 5,631,600	$ 10,755,597	$ 12,422,116	$ 783,171	$ 2,134,842
Operating Cash Balance						
Beg Balance	$ 25,619,100	$ 38,549,553	$ 44,181,154	$ 54,936,751	$ 67,358,868	$ 68,142,038
Annual Cash Flow	$ 12,930,453	$ 5,631,600	$ 10,755,597	$ 12,422,116	$ 783,171	$ 2,134,842
End Balance	$ 38,549,553	$ 44,181,154	$ 54,936,751	$ 67,358,868	$ 68,142,038	$ 70,276,880
Days of O&M Reserved	**82**	**84**	**108**	**130**	**130**	**132**
Target Minimum Days Cash	90	120	120	120	120	120
Annual Debt Service Coverage without PILOT Revenue						
Total System Achieved (Total Debt)	**1.92**	**1.75**	**1.75**	**1.78**	**1.86**	**1.85**
Target Minimum Coverage	1.60	1.60	1.60	1.60	1.60	1.60

1.7 Cost of Service Analysis

The class cost of service (COS) model allocates the BPU's total cost of service for the 2023 test year to each rate class based on principles of cost causation. The resultant class cost of service requirements are divided by the class billing units to develop unbundled unit costs of service for specific services provided to customers, which are used to guide the design base rates specific to the rate class.

- Allocation of test year cost of service (COS) to customer classes provides a measure of the proportionate share of cost responsibility for each class and a guide for developing fair, equitable and non-discriminatory rates.
- Test year revenue requirements are reduced by ERC and ESC revenues, interest on investments and other revenues to determine the net cost of service to be recovered through base rates.
- The net cost of service of $151.3 million includes the recommended 2.50% base rate increase for the test year 2023.

- In performing the cost allocation process, net cost of service is first functionalized into production, transmission, distribution, and customer related service categories. These functions are further classified into energy, demand, customer, and direct assigned cost classifications. Demand energy, and customer allocation factors are developed to assign the cost responsibility for each component to each rate class.

- The functional cost of service is allocated to each retail rate class, including the non-revenue producing municipal KCK and BPU interdepartmental rate classes. This cost of service for the non-revenue producing classes is allocated back to revenue producing retail rate classes on the basis of class cost of service.

- Table 1-4 shows the results of the cost of service analysis by class. The indicated percent changes in revenue requirements by class to cover costs for the class assuming each class produces uniform cost recovery range from a decrease of 6.6% for SGS to an increase of 11.5% for the Residential class.

- At this time, there is no justification for attempting to match cost of service and rates precisely. Based on the concept of gradualism, it is appropriate to move in the direction of matching costs and rates in gradual steps as discussed below.

Table 1-4: 2023 Cost of Service Summary by Rate Class

	Total System	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	USD 500	Private Area Lighting	KCK	BPU Interdepartmental
Cost of Service Summary										
Revenue Requirement	$ 151,326,325	$ 57,714,955	$ 15,766,386	$ 30,367,093	$ 10,718,146	$ 26,614,713	$ 4,285,166	$ 1,616,531	$ 2,686,724	$ 1,556,611
Revenue from Current Rates	$ 147,635,439	$ 53,092,238	$ 17,308,307	$ 31,960,311	$ 11,559,431	$ 27,320,996	$ 4,295,902	$ 1,596,941	$ -	$ 501,312
Class Deficiency	$ 3,690,886	$ 4,622,717	$ (1,541,922)	$ (1,593,218)	$ (841,285)	$ (706,283)	$ (10,736)	$ 19,590	$ 2,686,724	$ 1,055,299
Adjustment for KCK and BPU Deficiency	$ -	$ 1,468,359	$ 401,122	$ 772,587	$ 272,687	$ 677,120	$ 109,021	$ 41,127	$ (2,686,724)	$ (1,055,299)
Adjusted Class Cost of Service	$ 151,326,325	$ 59,183,315	$ 16,167,507	$ 31,139,680	$ 10,990,832	$ 27,291,833	$ 4,394,188	$ 1,657,658	$ -	$ 501,312
Indicated % Adjustment	**2.50%**	**11.47%**	**-6.59%**	**-2.57%**	**-4.92%**	**-0.11%**	**2.29%**	**3.80%**		
Energy Sales (kWh)	2,222,687,617	583,000,000	190,000,000	474,000,000	202,000,000	640,000,000	59,000,000	7,713,967	40,021,402	26,952,248
Rev. Requirement - $/kWh	$ 0.0681	$ 0.1015	$ 0.0851	$ 0.0657	$ 0.0544	$ 0.0426	$ 0.0745	$ 0.2149	$ -	$ 0.0186
Rev. from Current Rates	$ 0.0664	$ 0.0911	$ 0.0911	$ 0.0674	$ 0.0572	$ 0.0427	$ 0.0728	$ 0.2070	$ -	$ 0.0186
Difference	$ 0.0017	$ 0.0104	$ (0.0060)	$ (0.0017)	$ (0.0028)	$ (0.0000)	$ 0.0017	$ 0.0079	$ -	$ -
Indicated Adjustment	2.50%	11.47%	-6.59%	-2.57%	-4.92%	-0.11%	2.29%	3.80%	0.00%	0.00%

1.7.1.1 Target Rate Adjustments by Rate Class

Using the results of the cost of service study as a guideline, Table 1-5 presents the recommended class adjustments for each rate class for 2023 and 2024. The COS study indicates that the Residential class is under recovering its allocated costs by more than any other class. The SGS, MGS, and LGS classes are all over recovering their respective cost to serve. As such, we proposed that the Residential class receive more than the system average increase and the commercial and industrial classes receive less than the system average increase. We capped the maximum increase for any class at 150% of the system average, which results in a 3.75% increase for the residential class. The commercial and industrial classes receive less than the system average based on the lowest percentage that still allows the system to recover an overall increase of 2.50%.

Table 1-5: Target Class Base Revenue Adjustments

Base Rate Summary		
Class	**2023**	**2024**
Residential	3.75%	3.75%
Small General Service	1.75%	1.73%
Medium General Service	1.75%	1.73%
Large General Service	1.75%	1.73%
Large Power Service	1.75%	1.73%
USD 500	2.50%	2.50%
Private Area Lighting	2.50%	2.50%
BPU Interdepartmental	2.50%	2.50%

As the table illustrates, the increases are designed to move the various rate classes toward cost of service over time while avoiding disruptively large increases relative to the 2.50% increases in 2023 and 2024.

1.8 Rate Design

In practice, rates must be designed to recover the target revenues during the Rate Effective Period. The design of the rates includes not only the determination of the rate elements but also various rate provisions. Appendix B provides a revised Rate Application Manual, including the recommended rates. Recommended changes to the Rate Application Manual include the following:

- Merging of the standard Residential and Residential Electric Heat classes into one residential class that reflects the rate design of the current residential electric heating rate.
- Continuing the trend of increasing the Customer Charge to reflect cost of service and recovery of more fixed costs through fixed charges.
- Modifying the ERC rider to allow for additional recovery over costs to build and maintain an ERC Reserve fund.
- Creation of a Green Rider for customers that want to procure energy with renewable attributes.
- Other language changes within the Rate Manual to align the language with current BPU practice.

Each of these changes has been designed to clarify billing provisions identified by BPU staff or to improve the accuracy of rate mechanisms. Details of the rate proposals are presented in Section 5.0.

2.0 INTRODUCTION

This report presents the results of a comprehensive electric rate study (Study) prepared for the Kansas City Board of Public Utilities (BPU) by 1898 & Co., a division of Burns & McDonnell Engineering Company, Inc. (1898 & Co.). The BPU owns and operates the electric power generation, transmission, and distribution system serving customers located within, and areas outside the City of Kansas City, Kansas. The BPU uses a fiscal year (FY) ending December 31 (calendar year). Consistent with this, 1898 and Co. uses a forecast calendar year or years as test periods in its analysis.

2.1 Purpose

The purpose of this report is to evaluate the adequacy of the BPU's existing base rate charges and to recommend fair and equitable adjustments to the rates, if deemed necessary. 1898 & Co. designs utility rate studies to encompass three principal steps, each intended to answer questions typically asked by Boards and utility management. These steps are:

1) **Financial Planning** – Provides an indication of the overall adequacy of the revenue generated by current rates. The results of the financial forecast analysis answer the questions: "are the existing rates adequate?" and "if not, what level of overall revenue increase is needed?"

   To determine if the existing schedule of rates can be expected to generate enough revenue to meet the BPU's operating and capital costs, 1898 & Co. prepared a five-year financial projection of revenues and expenditures for the utility. A comparison of projected revenues under existing rates and planned expenditures provides insight into the adequacy of overall revenue levels.

   Our approach to Financial Planning involves the following basic steps:

   a. Project revenues under existing rates.
   b. Project utility expenditures.
   c. Develop a multi-year financial plan.
   d. Evaluate financial sufficiency based on key performance indicators such as cash reserve balances and debt service coverage.

2) **Cost of Service** – Focuses on assigning cost responsibility to customer classes. Each customer class is allocated an appropriate share of the overall system costs based on cost causation and the level of service provided. The net revenue requirements (costs to be recovered from rates) identified in step 1 are allocated to customers in accordance with industry standards, principles, and system specifics.

   The cost of service analysis was developed in the following steps:

   a. Determine the net revenue requirements to be recovered from user charges for a test year.
   b. Allocate test period operating and capital costs using industry standard allocation methods.
   c. Estimate the system test period units of service.
   d. Develop test period unit costs of service by class.

e. Assign the costs of service to customer classes.
f. Compare class allocated costs to revenue under existing rates by class.

3) **Rate Design** – Focuses on recommending revised rates and rate schedules that reflect cost of service considerations and practical rate implementation constraints.

   The rate design was developed for the BPU to progress towards the following goals:

   a. Rates should provide revenue stability for the utility.
   b. Rates should be simple and understandable.
   c. Rates should provide for a reasonable relationship to the cost of providing service.

2.2 Scope

This report presents the results of a comprehensive rate study of the electric utility and includes financial projections of the utility for the test periods of 2023-2027 to determine the overall adequacy of existing rates, a cost of service analysis, and rate recommendations for the utility.

The financial forecast reflects projections provided to 1898 & Co. by the BPU as well as our analysis of market trends in revenues and costs. Forecasted operating cost levels for subsequent years are based on the amount and degree of service, cost of system expansion and replacement, anticipated operating expenses and capital expenditures, assumed cost escalations, continuation of the current policy on transfers to the city, and other factors relevant to the utility. 1898 & Co. reviewed the financial projections and supporting assumptions provided by BPU and considers them appropriate for forecasting revenue requirements and rates.

3.0 REVENUE AND REVENUE REQUIREMENTS

The electric utility of the BPU provides service to residential, commercial, industrial, lighting, and municipal customers. The utility currently serves approximately 67,000 retail customers with projected base rate revenues under existing rates for 2022 of $145.5 million. Total retail energy sales are forecast to be 2.18 million megawatt hours (MWh) in 2022. This section summarizes the forecast of electric utility revenue and revenue requirements of the BPU for the period 2023 – 2027.

Overall adequacy of existing rates is tested by comparing revenues under existing rates with forecast revenue requirements, as presented in Table 3-4. To test the reasonableness of cost recovery by customer class rate schedules, electric utility revenue requirements are allocated to cost functions and to rate classes compared to rate class revenues. The cost of service analysis for the electric utility is presented in Section 4.0.

3.1 Financial Operations Under Existing Rates

The base rate revenue forecast under existing rates was generated by applying the existing base rates to the forecast of rate class billing determinants. The sales forecast of rate class billing determinants was prepared by applying specific growth rates by year to the 2021 actual billing determinants. The growth rates by class were derived from the 2022 load forecast prepared by BPU.

Total retail loads for 2022 were forecast to estimate year ending 2022 total retail sales of about 2,110 GWh. Total retail sales for 2023 are expected to be about 1.84% higher or approximately 2,148 GWh, with the increase generally being driven by a recovery of commercial load that decreased during the COVID pandemic. Annual energy growth is expected to remain mostly flat, with increases approximately 0.1% annually from 2023 – 2027. Retail sales growth is a function of new customer additions and added load net of conservation for existing customers.

A summary of the load forecast by rate class is shown in Table 3-1 and the application of it to forecast annual energy sales is shown in Table 3-2.

Table 3-1: Load Forecast

Forecast Change in Energy Sales by Class					
Description	**2023**	**2024**	**2025**	**2026**	**2027**
RATE 100 - RESIDENTIAL	-0.51%	0.35%	0.35%	0.35%	0.35%
RATE 200 - SMALL GENERAL SERVICE	1.66%	0.20%	0.20%	0.20%	0.20%
RATE 250 - MEDIUM GENERAL SERVICE	3.31%	0.20%	0.20%	0.20%	0.20%
RATE 300 - LARGE GENERAL SERVICE	1.81%	0.10%	0.10%	0.10%	0.10%
RATE 400 - LARGE POWER SERVICE	3.22%	-0.25%	-0.25%	-0.25%	-0.25%
RATE 500 - SCHOOL DISTRICT	0.00%	0.00%	0.00%	0.00%	0.00%

Table 3-2: Forecast of Energy Sales

Forecast of Annual Electric Sales (MWh)					
Description	**2023**	**2024**	**2025**	**2026**	**2027**
RATE 100 - RESIDENTIAL	583,000	585,041	587,088	589,143	591,205
RATE 200 - SMALL GENERAL SERVICE	190,000	190,380	190,761	191,142	191,525
RATE 250 - MEDIUM GENERAL SERVICE	474,000	474,948	475,898	476,850	477,803
RATE 300 - LARGE GENERAL SERVICE	202,000	202,202	202,404	202,607	202,809
RATE 400 - LARGE POWER SERVICE	640,000	638,400	636,804	635,212	633,624
RATE 500 - SCHOOL DISTRICT	59,000	59,000	59,000	59,000	59,000

Revenue related to recovery of retail fuel, purchased power, and ancillary charges are recovered through the Energy Rate Component (ERC) ERC rider. The 2022 Load Forecast provides the generation requirements for BPU's production cost model used to create a 5 year ERC forecast, which forecasts fuel and purchased power costs. While the ERC adjusts quarterly, a single annual ERC rate is used in the financial forecast and is equal to annual retail fuel and purchased power expense each year. This is done because the fuel and purchased power component of rates is a pass through of costs and this allows for the sole focus of the financial forecast to be on the base rate revenue.

Revenues under existing rates consist of three sources: base rate revenue, the environmental surcharge (ESC), and fuel and purchased power recovered in the ERC. The forecast of operating revenues under existing rates are shown in Table 3-3. As shown, the total rate revenue including base rates, ESC, and ERC ranges from $243.4 million in 2022 to $259.5 million in 2027. Other revenues, including PILOT, range from $34.2 million in 2022 to $36.3 million in 2027.

Total revenue under existing rates is summarized on Table 3-3 and ranges from $277.6 million in 2022 to $295.8 million in 2027.

Table 3-3: Revenue Under Existing Rates

Line	Description	12 Months Ended December 31, 2022	2023	2024	2025	2026	2027
		Projected	Budget	Forecast			
1	Retail Sales (MWh)	2,182,710	2,222,688	2,224,738	2,226,803	2,229,853	2,232,456
	REVENUES ($)						
2	**Base:**						
3	Retail Base Revenue	$ 145,449,569	$ 147,635,439	$ 147,870,862	$ 148,104,443	$ 152,513,395	$ 152,774,117
4	Borderline Margin	$ 539,713	$ 539,713	$ 594,913	$ 581,047	$ 573,425	$ 559,787
5	**Total Base Revenue**	**$ 145,989,282**	**$ 148,175,153**	**$ 148,465,775**	**$ 148,685,490**	**$ 153,086,820**	**$ 153,333,903**
6	**Fuel:**						
7	Retail ERC Revenue	$ 75,070,687	$ 82,396,864	$ 77,818,622	$ 79,537,283	$ 80,516,655	$ 82,214,647
8	Borderline Fuel Revenue	$ 710,494	$ 710,494	$ 655,294	$ 669,159	$ 676,782	$ 690,420
9	**Total Fuel Revenue**	**$ 75,781,181**	**$ 83,107,358**	**$ 78,473,915**	**$ 80,206,442**	**$ 81,193,437**	**$ 82,905,067**
10	Environmental Surcharge Revenue @ 1.3x Coverage	$ 21,671,387	$ 21,870,667	$ 22,475,022	$ 22,878,630	$ 22,970,330	$ 23,238,364
11	**Total Rate Revenue**	**$ 243,441,850**	**$ 253,153,178**	**$ 249,414,713**	**$ 251,770,563**	**$ 257,250,587**	**$ 259,477,335**
12	**Other Revenue:**						
13	PILOT Rate	11.90%	11.90%	11.90%	11.90%	11.90%	11.90%
14	PILOT	$ 28,969,580	$ 30,125,228	$ 29,680,351	$ 29,960,697	$ 30,612,820	$ 30,877,803
15	Forfeited Discounts	$ 1,182,230	$ 1,194,053	$ 1,205,993	$ 1,218,053	$ 1,230,234	$ 1,242,536
16	Connect/Disconnect Fees	$ 3,382,666	$ 3,416,492	$ 3,450,657	$ 3,485,164	$ 3,520,016	$ 3,555,216
17	Tower/Pole Attachment Rentals	$ 904,724	$ 913,771	$ 922,909	$ 932,138	$ 941,459	$ 950,874
18	Ash Disposal	$ -	$ -	$ -	$ -	$ -	$ -
19	Diversion Fines	$ 17,182	$ 17,354	$ 17,527	$ 17,703	$ 17,880	$ 18,059
20	Service Fees	$ 20,705	$ 20,912	$ 21,121	$ 21,332	$ 21,546	$ 21,761
21	Other Miscellaneous Revenues	$ (451,624)	$ (456,140)	$ (460,701)	$ (465,308)	$ (469,961)	$ (474,661)
22	Investment Income	$ 162,023	$ 138,942	$ 129,175	$ 119,407	$ 119,407	$ 119,407
23	**Total Other Revenue**	**$ 34,187,487**	**$ 35,370,613**	**$ 34,967,032**	**$ 35,289,185**	**$ 35,993,399**	**$ 36,310,994**
24	**Total Revenue**	**$ 277,629,337**	**$ 288,523,790**	**$ 284,381,745**	**$ 287,059,748**	**$ 293,243,987**	**$ 295,788,328**

3.2 Revenue Requirements

The overall adequacy of the existing rates is tested by comparing revenue under existing rates with revenue requirements. Revenue requirements are developed on a cash basis and consist primarily of fuel and purchased power expenditures, operation and maintenance (O&M) expenses, debt service requirements, transfers to other government agencies, reserve fund requirements, cash financed capital projects, and other non-operating expenses. The forecast of annual revenue requirements is shown in Table 3-4 and discussed in the following sections. Note that the line numbering is a continuation of Table 3-3 and row 24 is repeated on both tables.

Table 3-4: Forecast of Revenue Requirements

Line	Description	2022 Projected	2023 Budget	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast
		12 Months Ended December 31,					
24	**Total Revenue**	**$ 277,629,337**	**$ 288,523,790**	**$ 284,381,745**	**$ 287,059,748**	**$ 293,243,987**	**$ 295,788,328**
	REVENUE REQUIREMENTS ($)						
25	**Fuel Expense**						
26	Retail:						
27	Generation Fuel Costs	$ 57,320,394	$ 47,999,996	$ 52,443,000	$ 53,645,500	$ 55,050,000	$ 56,113,000
28	Purchased Power Costs	$ 163,194,400	$ 158,152,329	$ 154,626,243	$ 157,434,749	$ 160,304,711	$ 163,237,537
29	Less Integrated Market Sales	$ (145,444,107)	$ (123,755,461)	$ (129,250,621)	$ (131,542,966)	$ (134,838,055)	$ (137,135,890)
30	Total Retail Fuel/PP	$ 75,070,687	$ 82,396,864	$ 77,818,622	$ 79,537,283	$ 80,516,655	$ 82,214,647
31	Borderline Fuel Costs	$ 710,494	$ 710,494	$ 655,294	$ 669,159	$ 676,782	$ 690,420
32	**Total Fuel Expense**	**$ 75,781,181**	**$ 83,107,358**	**$ 78,473,915**	**$ 80,206,442**	**$ 81,193,437**	**$ 82,905,067**
33	**Operation and Maintenance Expense**						
34	Non-ERC Capacity Purchases	$ 2,600,000	$ 4,642,931	$ 4,642,931	$ 4,642,931	$ 4,642,931	$ 4,642,931
35	Production	$ 33,990,139	$ 40,065,184	$ 36,785,112	$ 37,319,914	$ 37,866,458	$ 38,437,508
36	Transmission	$ 4,472,702	$ 4,480,554	$ 4,543,959	$ 4,610,958	$ 4,681,392	$ 4,755,314
37	Distribution	$ 28,333,541	$ 30,822,838	$ 31,227,187	$ 31,641,417	$ 32,072,522	$ 32,524,876
38	Customer Accounts	$ 3,441,825	$ 3,514,947	$ 3,559,077	$ 3,606,481	$ 3,661,012	$ 3,718,752
39	Sales	$ -	$ 54,825	$ 54,825	$ 54,825	$ 54,825	$ 54,825
40	Administrative and General	$ 24,245,172	$ 27,136,471	$ 27,241,958	$ 27,350,399	$ 27,458,238	$ 27,569,019
41	Less Non-cash GASB 68 Item	$ (864,000)	$ (840,500)	$ (840,500)	$ (840,500)	$ (840,500)	$ (840,500)
42	**Total O&M Expense**	**$ 96,219,380**	**$ 109,877,250**	**$ 107,214,549**	**$ 108,386,425**	**$ 109,596,878**	**$ 110,862,725**
43	**Total Expenses**	**$ 172,000,560**	**$ 192,984,608**	**$ 185,688,464**	**$ 188,592,867**	**$ 190,790,314**	**$ 193,767,792**
44	**Net Revenues**	**$ 105,628,776**	**$ 95,539,183**	**$ 98,693,281**	**$ 98,466,881**	**$ 102,453,672**	**$ 102,020,536**
45	**Debt Service**						
46	Existing Capital Debt Service	$ 23,233,445	$ 23,252,127	$ 25,439,597	$ 25,121,815	$ 25,055,125	$ 24,858,254
47	Existing Environmental Debt Service	$ 16,670,298	$ 16,823,590	$ 17,288,479	$ 17,598,946	$ 17,669,485	$ 17,875,665
48	Proposed Capital Debt Service	$ -	$ -	$ 3,285,423	$ 3,285,423	$ 3,285,423	$ 3,285,423
49	Proposed Environmental Debt Service	$ -	$ -	$ -	$ -	$ -	$ -
50	**Total Debt Service**	**$ 39,903,743**	**$ 40,075,717**	**$ 46,013,499**	**$ 46,006,184**	**$ 46,010,033**	**$ 46,019,341**
51	Revenue After Debt Service Obligation	$ 65,725,033	$ 55,463,465	$ 52,679,782	$ 52,460,697	$ 56,443,640	$ 56,001,195
52	**Other Expenditures and Transfers**						
53	PILOT	$ 28,969,580	$ 30,125,228	$ 29,680,351	$ 29,960,697	$ 30,612,820	$ 30,877,803
54	Cash Financed Capital Projects	$ 23,100,000	$ 23,827,080	$ 23,110,201	$ 22,850,671	$ 38,043,640	$ 36,254,200
55	Heat Pump Program	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000	$ 225,000
56	Economic Development Fund Authorization	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000
57	**Total Other Exp. And Transfers**	**$ 52,794,580**	**$ 54,677,308**	**$ 53,515,552**	**$ 53,536,368**	**$ 69,381,460**	**$ 67,857,003**
58	**Total Revenue Requirement**	**$ 264,698,883**	**$ 287,737,633**	**$ 285,217,515**	**$ 288,135,419**	**$ 306,181,807**	**$ 307,644,136**
59	**Net Revenue Requirement**	**$ 230,511,397**	**$ 252,367,020**	**$ 250,250,483**	**$ 252,846,234**	**$ 270,188,408**	**$ 271,333,142**
60	Revenue Surplus / (Deficiency) Under Existing Rates	$ 12,930,453	$ 786,157	$ (835,770)	$ (1,075,671)	$ (12,937,820)	$ (11,855,808)

3.2.1 Fuel and Purchased Power Expenses

As discussed in section 3.1, the forecast of fuel and purchased power expenses is based on the ERC Forecast provided by BPU. The forecast of fuel and purchased power expenses is summarized on lines 27 through 32 of Table 3-4. Retail fuel, purchased power, and related costs recovered through the ERC are treated as a pass through expense. As such, ERC revenue and retail fuel revenue are set equal to retail fuel expense each year with no consideration of a seasonal true up.

The BPU has historically recovered certain fixed capacity costs of purchased power agreements (PPAs) in base rates instead of through the ERC. The current amount included in base rates is $2.6 million. As of 2023, these fixed capacity costs have increased to $4.64 million, and we are proposing to increase the amount recovered in base by $2.04 million to match the current and projected fixed capacity purchases.

3.2.2 Operation and Maintenance Expense

O&M expenses in the forecast period are based on the 2023 approved budget and escalated based on the following assumptions provided by the BPU:

Table 3-5: O&M Escalation Factors

Operations & Maintenance Escalation Rates				
Description	**2024**	**2025**	**2026**	**2027**
Personnel Costs	2.50%	2.50%	2.50%	2.50%
Services	2.00%	2.00%	2.00%	2.00%
Material and Supplies	2.00%	2.00%	2.00%	2.00%
Other Operating Expenses	1.00%	1.00%	0.00%	0.00%
Employee Healthcare/Medical	5.00%	5.00%	5.00%	5.00%
Retiree Healthcare/Medical	2.00%	2.00%	2.00%	2.00%

Certain items that are not appropriate for forecasting using an escalation rate, such as scheduled outages and major maintenance at generating stations, have been added or removed from the escalated forecast of O&M in the forecast period based on conversations with the BPU. O&M expenses are summarized on lines 33 through 41 of Table 3-4 and below in Table 3-6. 2023 includes an increase of $2.0 million in Non-ERC Capacity Purchases, that will remain flat throughout the study period. Production expense increase to $40.0 million in 2023 due to a planned major outage, then reduce back to typical inflationary increases through the remainder of the study period.

Table 3-6: O&M Forecast

Operation and Maintenance Forecast						
Description	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Non-ERC Capacity Purchases	$2,600,000	$4,642,931	$4,642,931	$4,642,931	$4,642,931	$4,642,931
Production	$33,990,139	$40,065,184	$36,785,112	$37,319,914	$37,866,458	$38,437,508
Transmission	$4,472,702	$4,480,554	$4,543,959	$4,610,958	$4,681,392	$4,755,314
Distribution	$28,333,541	$30,822,838	$31,227,187	$31,641,417	$32,072,522	$32,524,876
Customer Accounts	$3,441,825	$3,514,947	$3,559,077	$3,606,481	$3,661,012	$3,718,752
Sales	$0	$54,825	$54,825	$54,825	$54,825	$54,825
Administrative and General	$24,245,172	$27,136,471	$27,241,958	$27,350,399	$27,458,238	$27,569,019
Less Non-cash GASB 68 Item	($864,000)	($840,500)	($840,500)	($840,500)	($840,500)	($840,500)
Total O&M Expense	**$96,219,380**	**$109,877,250**	**$107,214,549**	**$108,386,425**	**$109,596,878**	**$110,862,725**

3.2.3 Capital Improvement Plan

The baseline capital improvement plan (CIP) is based on the 2023 budget, which provides a five-year (through 2027) capital plan. The primary and preferred source of funds to finance the electric utility CIP is annual operating revenues (cash financing). Debt financing is used to provide financing for the projects when surplus operating revenues are not sufficient to finance the entire CIP, or in the case of major projects with long life expectancies.

A summary of the 5-year CIP is shown in Table 3-7. Projects are grouped into specific categories depending on project type. Projects common to both the electric and water utilities start on line 23. 80% of the total common project costs are assigned to the electric utility.

Table 3-7: 5-Year Capital Improvement Plan

2023 Budget Capital Improvement Plan							
Line	**Description**	**2023**	**2024**	**2025**	**2026**	**2027**	**Total**
1	**Electric System Capital Projects**						
2	Electric Ops General Construction	945,000	1,595,000	1,595,000	1,595,000	1,595,000	7,325,000
3	Electric Production General Construction	702,000	702,000	50,000	50,000	50,000	1,554,000
4	Enterprise Telecommunications	10,000	10,000	10,000	10,000	-	40,000
5	Electric Meters	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	5,000,000
6	Electric Overhead Distribution	10,730,000	14,574,031	14,024,031	6,750,000	6,750,000	52,828,062
7	Electric Reimbursable	95,000	100,000	100,000	100,000	100,000	495,000
8	Electric - Storm Expenses	1,000	1,000	1,000	1,000	1,000	5,000
9	Electric Substations	215,000	3,340,000	6,540,000	9,690,000	690,000	20,475,000
10	Electric Transmissions	750,000	3,650,000	400,000	1,750,000	9,250,000	15,800,000
11	Electric Unified Gov't Project	760,000	560,000	260,000	260,000	260,000	2,100,000
12	Electric Underground Distribution	2,700,000	2,450,000	4,150,000	2,850,000	2,350,000	14,500,000
13	Electric Transformers	3,800,000	2,900,000	2,600,000	2,600,000	2,600,000	14,500,000
14	Nearman Power Plant CT4	620,000	365,000	400,000	400,000	400,000	2,185,000
15	Nearman Power Plant Unit 1	6,788,000	6,010,000	5,300,000	5,600,000	5,600,000	29,298,000
16	Nearman Power Plant Common	125,000	150,000	1,000,000	1,000,000	1,000,000	3,275,000
17	Quindaro Power Plant CT2	-	1,935,000	400,000	400,000	400,000	3,135,000
18	Quindaro Power Plant CT3	-	335,000	400,000	400,000	400,000	1,535,000
19	Quindaro Power Plant Common	340,000	340,000	340,000	340,000	340,000	1,700,000
20	Dogwood	365,000	206,000	880,000	355,000	355,000	2,161,000
21	Electric Control Center	1,219,640	846,530	-	-	-	2,066,170
22	**Total Electric Capital Projects**	**$ 31,165,640**	**$ 41,069,561**	**$ 39,450,031**	**$ 35,151,000**	**$ 33,141,000**	**179,977,232**
23	Common Facility Improvements	170,000	160,000	160,000	160,000	160,000	810,000
24	Common Furnish and Equipment	30,000	30,000	30,000	30,000	32,500	152,500
25	Common Grounds	175,000	75,000	75,000	75,000	75,000	475,000
26	Enterprise Technology	4,146,000	4,155,000	3,405,000	2,770,000	3,045,000	17,521,000
27	Administrative Service Technology	505,800	505,800	505,800	505,800	509,000	2,532,200
28	HR Security Improvements	175,000	125,000	75,000	75,000	70,000	520,000
29	**Total Common Capital Projects**	**$ 5,201,800**	**$ 5,050,800**	**$ 4,250,800**	**$ 3,615,800**	**$ 3,891,500**	**22,010,700**
30	Electric Share Adjustment - 80%	4,161,440	4,040,640	3,400,640	2,892,640	3,113,200	17,608,560
31	**Electric Total CIP**	**$ 35,327,080**	**$ 45,110,201**	**$ 42,850,671**	**$ 38,043,640**	**$ 36,254,200**	**$ 197,585,792**

3.2.4 CIP Financing and Debt Service

The CIP is financed with a mix of debt financing (revenue bonds) and cash financing from annual rate revenues. In developing the financial forecast, it was determined that the base rate increases needed to fully fund the CIP with annual operating revenues would be too large. As a result, 1898 & Co. collaborated with BPU to find a balanced approach that uses a mix of revenue bonds and cash financing that moderates the need for base rate increases and still maintains debt service coverage above the 1.60x target. We recommend a $50 million revenue bond issuance in 2023 to fund a portion of projects identified in the CIP in 2023, 2024, and 2025. The funds from the bond issuance will help finance the CIP and free up cash in order to increase days cash on hand. Debt service coverage will decrease slightly but remains in a healthy position over the 1.60 ratio included in the BPU's financial guidelines.

The proposed CIP financing plan is summarized in Table 3-8. Alternative funding sources in 2023 and 2024 consist of prior issue bond proceeds and grant funding. Bond financed capital projects is the recommended distribution of the additional $50 million. The remaining amount will be funded by cash sourced from annual rate revenues.

Table 3-8: CIP Financing Plan

Capital Improvement Plan Financing					
Description	**2023**	**2024**	**2025**	**2026**	**2027**
Beginning Fund Balance	1,500,000	40,000,000	20,000,000	-	-
Sources of Funds	-	-	-	-	-
Cash Funded Capital Projects	23,827,080	23,110,201	22,850,671	38,043,640	36,254,200
Environmental Bond Proceeds at Par	-	-	-	-	-
Capital Bond Proceeds at Par	50,505,000	-	-	-	-
EDA Grant	-	2,000,000	-	-	-
Total Sources	**74,332,080**	**25,110,201**	**22,850,671**	**38,043,640**	**36,254,200**
Uses of Funds	-	-	-	-	-
Capital Improvements	35,327,080	45,110,201	42,850,671	38,043,640	36,254,200
Capitalized Interest Payment	-	-	-	-	-
Debt Issuance Expense	505,000	-	-	-	-
Total Uses	**35,832,080**	**45,110,201**	**42,850,671**	**38,043,640**	**36,254,200**
Ending CIP Fund Balance	**40,000,000**	**20,000,000**	**-**	**-**	**-**

Total debt service is shown on line 49 of Table 3-4 and ranges from $40.1 - $46.0 million throughout the study period, with proposed debt service increasing by $3.3 million per year beginning in 2024. No additional bonds that would be recovered through the Environmental Surcharge are projected during the study period.

3.2.5 Other Expenditures and Transfers

The electric utility transfers money to the Unified Government of Wyandotte County and Kansas City, Kansas (UG) in the form of a payment in lieu of taxes (PILOT). The UG sets the rate on an annual basis and the BPU collects the revenue on electric bills and transfers the funds to the UG. The current and expected future PILOT payment is 11.9% of adjusted gross revenues (gross revenue less off system sales fuel revenue). The gross transfer is shown on line 53 of Table 3-4 and ranges from $29.0 to $30.9 million under existing rates.

Other expenditures include cash financed capital, the heat pump rebate program, and the economic development fund shown on lines 54-56 of Table 3-4.

3.2.6 Key Financial Metrics

The adequacy of existing rates is measured using some key financial metrics defined by the financial policies of the Board. The two primary measures are debt service coverage and the level of operating cash reserves maintained by the BPU, measured in Days of O&M Reserved. The BPU currently does not have adequate operating cash reserve funds to maintain liquidity in accordance with stated financial guidelines. As stated in the recommended changes to the

Board's Financial Guidelines, the BPU shall maintain a cash reserve for operating expenses of 120 days or better of annual operating expenditures, including costs recovered through the ERC. The recommended changes are discussed further in Section 3.3.3.

Based on the financial forecast, the minimum cash operating reserve should be approximately $63.5 million in 2023 and increase to $63.7 million in 2027. The forecasted electric cash operating reserve balance at the end of 2022 does not meet this level and continues to decline throughout the study period without additional base rate increases and the bond issuance. The projected base rate increases, $50 million bond issuance, and the creation of an ERC cash reserve help to build and maintain the operating reserves above the 120 day recommendation by 2025.

3.2.7 Bond Coverage Requirements

An additional consideration in measuring the adequacy of revenues is the provision of sufficient debt service coverage to meet the bond covenant requirements for the issuance of parity revenue bonds. Bonds for the electric and water utilities are issued as combined utility revenue bonds, therefore, debt service coverage is considered for the two utilities on combined basis; however, it is appropriate and prudent to examine the ability of the electric utility to meet bond coverage requirements as an individual entity.

Revenue bonds are governed by the Second Amended and Restated Indenture of Trust (Trust Indenture), which provides that utility rates shall be maintained according to the following provision:

2) *The Issuer, through the BPU, shall, in accordance with applicable legal requirements, establish. maintain and collect rates. fees and charges with impact to the facilities of, and services rendered by, the Utility System, that, together with other available funds available to be transferred from the Rate Stabilization Fund as permitted in Section 509(c), will produce revenues at least sufficient in each Fiscal Year, to*

    (1) pay or make provision for the payment of Operation and Maintenance Expenses to be paid or accrued in such Fiscal Year and all deposits required to be made by Section 504(a), (b) and (c); and

    (2) provide Net Revenues during such Fiscal Year that will be equal to not less than (i) so long as any Series 2009-A Bonds remain Outstanding, 120% of the Maximum Annual Debt Service with respect to all Bonds, Parity Indebtedness and Subordinated Indebtedness in any Fiscal Year, or (ii) if no Series 2009-A Bonds remain Outstanding. ***120% of the Average Annual Debt Service Requirements with respect to all Bonds****, Parity Indebtedness and Subordinated Indebtedness in any Fiscal Year.*[2]

While PILOT revenue is allowed to be included in the determination of net revenue, the BPU has received feedback from rating agencies that they do evaluate coverage without the benefit of PILOT revenues, since the BPU remits these revenues directly back to the UG.

[2] Second Amended and Restated Indenture of Trust, Section 705(c)(2)

Furthermore, the bond Trust Indenture provides that rates shall be maintained such that net revenues are sufficient to not only satisfy the debt service coverage requirement but also, among other things, make all required PILOT payments. Thus, as a practical matter, coverage should be evaluated without the benefit of PILOT revenues. The BPU has established a financial guideline that net revenue for the electric utility should be equal to 160 percent of average annual debt service.

3.2.8 Summary of Revenue Requirements Under Existing Rates

The net annual operating deficiency under existing rates is shown on line 59 of Table 3-4 and summarized on Table 3-9. The operating deficiency by 2027 is $11.7 million. Debt service coverage for the purpose of rate setting is based on annual debt service coverage, which is net revenues available for debt service divided by the annual debt service payment. Using Table 3-4 as a reference, net revenues available for debt service is defined as Total Revenue (line 24) less PILOT revenue (line 14) minus total fuel and operating expenses (line 43). This value is divided by the net annual debt service payment (line 50) to calculate the debt service coverage ratio. The target ratio is 1.60.

Table 3-9: Financial Metrics Under Existing Rates

Financial Metrics Under Existing Rates						
Description	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Revenue Surplus / (Deficiency) Under Existing Rates	$ 12,930,453	$ 786,157	$ (835,770)	$ (1,075,671)	$ (12,937,820)	$ (11,855,808)
Operating Cash Balance						
Beg Balance	$ 25,619,100	$ 38,549,553	$ 39,335,710	$ 38,499,941	$ 37,424,270	$ 24,486,449
Annual Cash Flow	$ 12,930,453	$ 786,157	$ (835,770)	$ (1,075,671)	$ (12,937,820)	$ (11,855,808)
End Balance	$ 38,549,553	$ 39,335,710	$ 38,499,941	$ 37,424,270	$ 24,486,449	$ 12,630,642
Days of O&M Reserved	**82**	**74**	**76**	**72**	**47**	**24**
Target Minimum Days Cash	90	120	120	120	120	120
Annual Debt Service Coverage without PILOT Revenue						
Total System Achieved (Total Debt)	**1.85**	**1.61**	**1.48**	**1.47**	**1.54**	**1.53**
Target Minimum Coverage	1.60	1.60	1.60	1.60	1.60	1.60

As shown in Table 3-9, current debt service coverage ratios are sufficient for 2023. Without base rate increases, debt service coverage drops below the 1.60 target beginning in 2024. In addition, cash balances are currently below the recommended 120 days and continue to erode through the study period.

3.3 Overall Revenue Adequacy and Recommended Adjustments

Based on the projection of revenue and revenue requirements, there are adjustments indicated for the electric utility. The BPU is not able to adequately finance its CIP and still meet its projected operating reserve and debt service coverage requirements. As shown on Table 3-9, annual debt service coverage for the electric utility under existing rates drops from 1.85 in 2022 to 1.53 in 2027, below the stated target of 1.60. Deficiencies in electric revenues and debt service coverage projections also indicate that the ability of the combined utility to meet the required minimum debt service coverage ratio over the study period under the bond Trust Indenture, as well as to make the required PILOT payments, while financing CIP and operating requirements, is challenged under existing rates.

3.3.1 Recommended Rate Adjustments

Based on the forecast of revenues under existing rates, revenue requirements, the minimum prudent reductions in operating expenses and capital expenditures, and the accumulation of prudent liquidity reserves over the period, the recommended percentage rate adjustments through 2024 are:

Table 3-10: Recommended Base Rate Adjustments

Description	2023	2024
Recommended Base Rate Increase	2.5%	2.5%
Date of Increase	July 1, 2023	July 1, 2024

The recommended minimum adjustments result in a cumulative base revenue increase of $30.9 million through the 2023 – 2027 study period. These increases assist the BPU in meeting target financial metrics for debt service coverage and operating reserves. The BPU management team is committed to managing its costs and strengthening financial metrics during this period in order to build healthy cash reserves.

3.3.2 Key Drivers for Rate Increases

There are many interrelated issues that can lead to the need for rate increases. The most common include inflationary increases to operating costs, issuance of new debt, loss of customer load, maintaining adequate debt service coverage and cash reserves, and changes in non-retail customer sources of revenue. The two largest drivers of rate adjustments for BPU in the instant case are inflationary O&M and materials costs and significantly deficient cash reserve levels. An additional driver is the transfer of over $2.0 million in PPA capacity costs that are being transferred from the ERC to base rates, which has no overall impact on customers' bills.

BPU has not increased base rates since 2018 and over that time it has done an excellent job at refinancing debt to lower rates and controlling costs to prevent rate increases. Those cuts and the erosion of cash balances have reached a tipping point that can no longer be avoided without a base rate increase.

3.3.3 Recommended Changes to Reserve Funds

Following a review of BPU's Financial Policies and making recommendations for adjustments, a key recommended change is how BPU manages and tracks its cash operating reserve levels. Historically, maintaining sufficient operating reserves has been a challenge for BPU and it has been a driver for rate increases in BPU's last two rate hearings in 2010 and 2016. Rather than simply measure days cash on hand at any given time during the year based on unrestricted cash on the balance sheet, we recommend BPU create two distinct funds on the balance sheet for operating reserves. The two funds are an O&M Reserve Fund and an ERC Reserve Fund. The BPU holds a single A or A2 rating with the rating agencies. The typical operating reserve for this level is between 90 and 180 days. We recommend increasing BPU's target days cash on hand to 120 days from the current 60 days. While this is still at the lower end of the range for an A rated utility, it provides some cushion below the bottom of the benchmark range. The ability for BPU to maintain its current rating will allow it to continue to issue bonds at reasonable interest rates.

The O&M Reserve Fund will hold a target of 120 days of annual non-ERC operating costs. Non-ERC operating costs include all non-ERC production O&M, non-ERC Capacity Purchases recovered in base rates, transmission and distribution O&M, Customer and Sales expense, and Administrative and General costs. The target for each year will be based on the current year's approved budget. The official measure of days cash on hand will be at the end of each fiscal year. It is expected that some fluctuation above and below 120 days will occur. Having the liquidity to manage these fluctuations is the reason for funding these reserves in the first place. This fund will be applicable to both the electric and water utilities.

Due to the volatile nature of power supply costs, which often puts pressure on a utility's cash balances, 1898 & Co. recommended creating a reserve tied directly to variable fuel and purchased power costs recovered in the ERC. In prior rate cases, if cash balances are declining due to the timing of cost recovery through ERC Rider, operating cash funded through base rate increases was the only option for making up the temporary differences. Creation of an ERC Reserve eliminates that need. The overall level of rate increases will remain the same – the difference is if the ERC Reserve did not exist, base rate increases would need to be higher to make up the difference.

We recommend the BPU gradually fund the ERC Reserve over five years, rather than all at once. Based on current projections of costs recovered through the ERC, the reserve fund will be approximately $27 million by 2027. We recommend funding this in generally equal amounts by increasing the quarterly ERC amount by $1.5 million, which translates to an increase in the fund of about $6 million per year. This funding plan is shown below in Table 3-11:.

Table 3-11: Funding Plan for ERC Reserve Fund

Funding Plan for ERC Reserve					
Description	**2023**	**2024**	**2025**	**2026**	**2027**
Projected Expenses Recovered in ERC	$ 83,107,358	$ 78,473,915	$ 80,206,442	$ 81,193,437	$ 82,905,067
Target ERC Reserve @ 120 days	$ 27,322,967	$ 25,799,643	$ 26,369,241	$ 26,693,733	$ 27,256,460
Additional Cost Recovered in ERC	**$ 3,000,000**	**$ 6,000,000**	**$ 6,000,000**	**$ 6,000,000**	**$ 6,256,460**
Variance from Target ERC Reserve	$ (24,322,967)	$ (16,799,643)	$ (11,369,241)	$ (5,693,733)	$ (0)

3.4 Forecast Revenue Under Recommended Rate Adjustments

The forecast of revenues under proposed rates is shown on Table 3-12. Planned rate adjustments are effective on July 1st of each year and therefore only produce about 50% of the revenue in the year of implementation versus a full year rate increase. The other notable change on this table is the addition of the ERC Reserve funding on line 12.

Table 3-12: Revenue Under Proposed Rates

Line	Description	Effective Date	% Increase	Remaining Months in FY	2022	2023	2024	2025	2026	2027
					12 Months Ended December 31,					
					Projected	Budget	Forecast			
1	Retail Sales (MWh)				2,182,710	2,222,688	2,224,738	2,226,803	2,229,853	2,232,456
	Revenues ($)									
2	**Base Rate Revenue Under Existing Rates**				**$ 145,449,569**	**$ 147,635,439**	**$ 147,870,862**	**$ 148,104,443**	**$ 152,513,395**	**$ 152,774,117**
3		July 1, 2023	2.50%	6		$ 1,845,443	$ 3,696,772	$ 3,702,611	$ 3,812,835	$ 3,819,353
4		July 1, 2024	2.50%	6			$ 1,894,595	$ 3,795,176	$ 3,908,156	$ 3,914,837
5		January 1, 2025	0.00%	12				$ -	$ -	$ -
6		January 1, 2026	0.00%	12					$ -	$ -
7		January 1, 2027	0.00%	12						$ -
8	**Additional Base Rate Revenue**				**$ -**	**$ 1,845,443**	**$ 5,591,367**	**$ 7,497,787**	**$ 7,720,991**	**$ 7,734,190**
9	Borderline Margin				$ 539,713	$ 539,713	$ 594,913	$ 581,047	$ 573,425	$ 559,787
10	**Total Base Revenue**				**$ 145,989,282**	**$ 150,020,596**	**$ 154,057,142**	**$ 156,183,278**	**$ 160,807,811**	**$ 161,068,093**
	Fuel:									
11	Retail ERC Revenue				$ 75,070,687	$ 82,396,864	$ 77,818,622	$ 79,537,283	$ 80,516,655	$ 82,214,647
12	Build ERC Cash Reserve				$ -	$ 3,000,000	$ 6,000,000	$ 6,000,000	$ 6,000,000	$ 6,256,460
13	Borderline Fuel Revenue				$ 710,494	$ 710,494	$ 655,294	$ 669,159	$ 676,782	$ 690,420
14	**Total Fuel Revenue**				**$ 75,781,181**	**$ 86,107,358**	**$ 84,473,915**	**$ 86,206,442**	**$ 87,193,437**	**$ 89,161,527**
15	Environmental Surcharge Revenue @ 1.3x Coverage				$ 21,671,387	$ 21,870,667	$ 22,475,022	$ 22,878,630	$ 22,970,330	$ 23,238,364
16	**Total Rate Revenue**				**$ 243,441,850**	**$ 257,998,621**	**$ 261,006,080**	**$ 265,268,350**	**$ 270,971,578**	**$ 273,467,984**
	Other Revenue:									
17	PILOT Rate				11.90%	11.90%	11.90%	11.90%	11.90%	11.90%
18	PILOT				$ 28,969,580	$ 30,701,836	$ 31,059,724	$ 31,566,934	$ 32,245,618	$ 32,542,690
19	Forfeited Discounts				$ 1,182,230	$ 1,194,053	$ 1,205,993	$ 1,218,053	$ 1,230,234	$ 1,242,536
20	Connect/Disconnect Fees				$ 3,382,666	$ 3,416,492	$ 3,450,657	$ 3,485,164	$ 3,520,016	$ 3,555,216
21	Tower/Pole Attachment Rentals				$ 904,724	$ 913,771	$ 922,909	$ 932,138	$ 941,459	$ 950,874
22	Ash Disposal				$ -	$ -	$ -	$ -	$ -	$ -
23	Diversion Fines				$ 17,182	$ 17,354	$ 17,527	$ 17,703	$ 17,880	$ 18,059
24	Service Fees				$ 20,705	$ 20,912	$ 21,121	$ 21,332	$ 21,546	$ 21,761
25	Other Miscellaneous Revenues				$ (451,624)	$ (456,140)	$ (460,701)	$ (465,308)	$ (469,961)	$ (474,661)
26	Investment Income				$ 162,023	$ 138,942	$ 129,175	$ 119,407	$ 119,407	$ 119,407
27	**Total Other Revenue**				**$ 34,187,487**	**$ 35,947,221**	**$ 36,346,405**	**$ 36,895,422**	**$ 37,626,197**	**$ 37,975,881**
28	**Total Revenue**				**$ 277,629,337**	**$ 293,945,841**	**$ 297,352,485**	**$ 302,163,772**	**$ 308,597,775**	**$ 311,443,866**

All revenue requirements are the same as shown in Table 3-4 with the exception of PILOT, which increases with rate revenue. We show a summary of the key financial metrics under proposed rates on Table 3-13. As shown in the summary, the recommended adjustments maintain positive cash flow while increasing operating reserves above the recommended 120 days by 2025. Annual debt service also stays comfortably above the 1.60 target throughout the study period. Maintaining operating reserves and debt service slightly above the recommended targets allows the BPU additional financial security in the event of unexpected or unforeseen circumstances in the coming years.

Table 3-13: Key Financial Metrics Under Proposed Rates

Financial Metrics Under Proposed Rates						
Description	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Revenue Surplus / (Deficiency) Under Proposed Rates	$ 12,930,453	$ 5,612,982	$ 10,755,597	$ 12,422,116	$ 783,171	$ 2,134,842
Operating Cash Balance						
Beg Balance	$ 25,619,100	$ 38,549,553	$ 44,162,535	$ 54,918,133	$ 67,340,249	$ 68,123,420
Annual Cash Flow	$ 12,930,453	$ 5,612,982	$ 10,755,597	$ 12,422,116	$ 783,171	$ 2,134,842
End Balance	$ 38,549,553	$ 44,162,535	$ 54,918,133	$ 67,340,249	$ 68,123,420	$ 70,258,262
Days of O&M Reserved	**82**	**84**	**108**	**130**	**130**	**132**
Target Minimum Days Cash	90	120	120	120	120	120
Annual Debt Service Coverage without PILOT Revenue						
Total System Achieved (Total Debt)	**1.92**	**1.75**	**1.75**	**1.78**	**1.86**	**1.85**
Target Minimum Coverage	1.60	1.60	1.60	1.60	1.60	1.60

4.0 COST OF SERVICE ANALYSIS

The overall adequacy of rates is tested by comparing class revenues under existing rates for a test year with the class allocated test year revenue requirements. The Electric Utility's cost of service requirements are set equal to the net revenue requirements of the utility to be recovered from rates. Test year costs of service are first functionalized and classified to cost functions, and then allocated to customer classes on appropriate allocation bases, and finally the allocated class cost of service is compared to test year class revenue. This section presents the unbundled class cost of service analysis for the BPU electric system based on the projected FY 2023 base revenues and costs. The functionalization, classification, and allocation major groups are shown on Table 4-1.

Table 4-1: Cost of Service Cost Functions, Classifications, & Allocations

Functionalization	Classification	Allocation
Production/Generation	Energy	Residential
Transmission	Demand	Small General Service
Distribution	Customer	Medium General Service
Customer	Direct Assignment	Large General Service
Direct Assignment		Large Power Service
		USD 500
		Lighting

Table 4-1 presents a summary of Electric Utility revenue requirements, or cost of service to be allocated to classes, for test year 2023. Net revenue requirements include O&M expenses, debt service, capital expenditures, reserve fund obligations, and transfers. Credits to the cost of service include other revenues and interest income, which reduce base rate revenue requirements.

Pro forma adjustments, shown in Table 4-2, are adjustments to reflect the amount of cost and associated revenue not recovered in base rates. These include fuel costs and purchased power costs recovered through the ERC, billed directly to borderline customers, and PILOT. A margin adjustment is included to account for a partial year rate increase. The last column of Table 4-2 presents the Test Year net cost of service of $151.3 million to be recovered through base rates.

The detailed development of unbundled cost of service is discussed in the following sections.

Table 4-2: 2023 Test Year Cost of Service

Test Year Cost of Service				
Description	**2023 Test Year**	**Pro Forma Adjustment**	**Notes**	**Test Year Base COS**
CASH BASIS				
Revenue Requirements				
Fuel Expense				
Retail Fuel and Purchased Power Costs	82,396,864	(82,396,864)	(a)	-
Borderline Fuel Costs	710,494	(710,494)	(c)	-
Total Fuel Expense	**$ 83,107,358**	**$ (83,107,358)**		**$ -**
Operation and Maintenance Expense				
Non-ERC Capacity Purchases	4,642,931			4,642,931
Production	40,065,184			40,065,184
Transmission	4,480,554			4,480,554
Distribution	30,822,838			30,822,838
Customer Accounts	3,514,947			3,514,947
Sales	54,825			54,825
Administrative and General	26,295,971			26,295,971
Total O&M Expense	**$ 109,877,250**	**$ -**		**$ 109,877,250**
Total Operating Expenses	**$ 192,984,608**	**$ (83,107,358)**		**$ 109,877,250**
Debt Service				
Existing Capital Debt Service	23,252,127			23,252,127
Existing Environmental Debt Service	16,823,590		(b)	16,823,590
Proposed Capital Debt Service	-			-
Total Debt Service	**$ 40,075,717**	**$ -**		**$ 40,075,717**
Other Expenditures and Transfers				
PILOT	30,701,836	(30,701,836)	(d)	-
Cash Financed Capital Projects	23,827,080	-		23,827,080
Heat Pump Program	225,000	-		225,000
Economic Development Fund Authorization	500,000	-		500,000
Change in Operating Balance	-	5,631,600		5,631,600
Total Other Exp. And Transfers	**$ 55,253,916**	**$ (25,070,236)**		**$ 30,183,680**
Total Revenue Requirements	**$ 288,314,241**	**$ (108,177,593)**		**$ 180,136,648**
Less: Other Revenue				
PILOT	30,701,836	(30,701,836)	(d)	-
Forfeited Discounts	1,194,053	-		1,194,053
Connect/Disconnect Fees	3,416,492	-		3,416,492
Tower/Pole Attachment Rentals	913,771	-		913,771
Diversion Fines	17,354	-		17,354
Service Fees	20,912	-		20,912
Other Miscellaneous Revenues	(456,140)	-		(456,140)
Investment Income	138,942	-		138,942
Environmental Surcharge	21,870,667	-	(b)	21,870,667
Transfer to ERC Cash Reserve	3,000,000	-		3,000,000
Borderline Margin	539,713	-		539,713
Total Other Revenue	**61,357,601**	**(30,701,836)**		**30,655,765**
Total Revenue Requirement	**$ 226,956,640**	**$ (77,475,757)**		**$ 149,480,882**
Margin Adjustment	-	1,845,443		1,845,443
Net Revenue Requirement	**$ 226,956,640**	**$ (75,630,314)**		**$ 151,326,325**
Revenues				
Retail Base Revenues	147,635,439			147,635,439
ERC Revenues	82,396,864	(82,396,864)	(a)	-
Borderline Fuel Costs	710,494	(710,494)	(c)	-
Total Revenues	**$ 230,742,797**	**$ (83,107,358)**		**$ 147,635,439**
Base Revenue Increase				
Amount				$ 3,690,886
Percent				2.50%

(a) Fuel and Purchased Power recovered in ERC
(b) Environmental Debt Service recovered in ESC
(c) Borderline costs removed from Base Rate COS
(d) PILOT direct billed to customers, not included in Cost of Service

4.1 Functionalization and Classification of Revenue Requirements

1898 & Co. uses a systematic process for identifying functions based on the traditional utility categories of production (generation), transmission, distribution, and customer. 1898 & Co. further splits customer between onsite distribution and general customer. This latter split is useful for assuring that rate design at least recovers the onsite costs (meter, service line, transformer investment and customer service and billing) and direct costs in the customer component of rates. General customer related costs for the Distribution system are tracked separately as well as the customer components of general plant and non-payroll related overheads (which are allocated on direct payroll).

To the extent permitted by the accounting data, this functionalization may include subcategories such as primary Distribution and secondary Distribution and directly assigned dollars based on unique facilities that need to be assigned rather than allocated. Cost classification is driven by as detailed an analysis as the accounting and load data permits. Costs are classified as demand, energy, and customer. Only costs that vary with energy are classified as energy.

4.1.1 Functionalization of Test Year Cost of Service

Multiple functional services were identified while analyzing the BPU's cost categories. Each cost category and its subordinate functional services are summarized below.

- Production
- Transmission
- Distribution
    - Distribution Substation
    - Distribution Primary Lines & Poles
    - Distribution Secondary Lines & Poles
    - Distribution Services
    - Distribution Metering
- Customer
    - Lighting
    - Customer Service & Accounts
    - Base Rate Revenue
- Direct
-

The **production** function consists of the non-fuel costs of power generation and purchased power. Fuel and variable purchased power costs are recovered in a separate ERC rider and not considered in this cost of service study, which evaluates base rate recovery only. Fuel and variable purchased power costs are effectively allocated to customers on an energy basis through the ERC.

The **transmission** function consists of the assets and expenses associated with the high voltage system used by the electric system (69 kV and above) to interconnect with the grid and to move power from generation to load.

The **distribution** function includes the system that connects transmission to loads. Different customers use different components of the distribution system. Thus, it is common for the distribution system to be divided into sub-functions such as primary and secondary. In addition, some distribution facilities serve a customer function and are further subdivided based on the type of facilities used by customer groups.

The **customer** function includes plant and expenses associated with individual customers and includes meter, services, along with meter reading and billing (accounts and services) for example.

The **direct** function is used to assign certain costs directly to a specific class, such as heat pump rebates and economic development. It is also used to allocate specific costs on a basis not covered by the other functions. These include Direct Assignment and Base Rate Revenue.

On the surface, the functionalization process has been greatly simplified by the adoption of FERC uniform systems of accounts (USOA). Thus, plant accounts from 310-346 represent production plant and expenses from 500-557 represent expenses for production. Similar accounts exist for the other functions. Each of the accounts identifies a specific cost component such as land and land rights. There is an account for this category of expense for each type of production capacity and for transmission, distribution, and general plant. The accounting system provides most of the functionalization necessary for cost allocation.

4.1.2 Classification of Test Year Cost of Service

Costs are classified as energy, demand, customer, and direct. Energy costs are those costs that vary generally with the production of energy such as fuel costs, purchased power expense, certain boiler and steam expenses, or other variable generation costs. Demand costs are those costs that vary generally with some measure of maximum demand. Measures of maximum demand include coincident peak demand, class non-coincident peak demand, and customer non-coincident peak demand. Customer costs are those costs that vary generally with the number of customers, such as meters and service lines. Some costs may be classified into more than one category. For example, some distribution costs may have both a capacity and a customer cost component. For example, overhead conductor is a function of customers because the miles of line required changes with customer density. That is, some portion of the system is directly related to the number of customers per mile of line. The actual size of line is related to either the class non-coincident peak demand for lines remote from customers or to the customer non-coincident peak for lines in close proximity to the customer. The difference in classification results from the increased level of diversity occurring in customer loads as facilities become more remote from the customer. The classification of costs has now been added to the list of functions below.

- Production
  - Production Energy
  - Production Demand
- Transmission
  - Transmission Demand
- Distribution
  - Distribution Demand Substation
  - Distribution Demand Primary Lines & Poles
  - Distribution Customer Secondary Lines & Poles
  - Distribution Customer Services

    - Distribution Customer Metering
- Customer
    - Customer Lighting
    - Customer Service & Accounts
    - Base Rate Revenue
- Direct

4.1.3 Revenue Requirement Classification

The way each component was assigned to the functional services varied based on the nature of the item. 1898 & Co. developed the proposed unbundling of the components of the FY 2023 revenue requirement based on its understanding of the types of associated costs. A summary of the assignment of each component of the test year revenue requirement is presented in Table 4-4. The assignment of the components of the test year revenue requirement for FY 2023 shows that $78.6 million, or approximately 52% of the BPU's test year net revenue requirement is related to production.

4.1.4 Revenue Requirement Allocation

Following the unbundling of the various components of the test year revenue requirement to the functional utility services, the unbundled test year revenue requirement was allocated to the electric utility's retail rate classifications. These allocations were developed to reflect the relative impact each rate class will have on the level of each component of the test year revenue requirement. The test year revenue requirement was allocated to the Residential, Residential Heating, Small General Service, Small General Service Heating, Medium General Service, Medium General Service Heat, Large General Service, Large Primary Service, Large Primary Service Heat, School District, Private Area Lighting, and BPU Interdepartmental classes.

Table 4-3: Summary of Functionalization and Classification of Plant in Service

Functionalization and Classificaiton of Fixed Assets														
Description	Plant in Service as of December 31, 2021	Production		Transmission	Distribution						Customer			Direct
		Energy	Demand	Demand	Demand				Customer		Customer			Direct
					Substations	Transformers	Lines Prim	Lines Sec	Services	Meters	Lighting	Cust Accounts	Base Rev	
Total Produciton Plant	**$ 807,278,334**	**$ -**	**$ 807,278,334**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Transmission Plant	**$ 93,146,008**	**$ -**	**$ -**	**$ 93,146,008**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Distribution Plant														
Land and Land Rights	$ 457,363	$ -	$ -	$ -	$ 457,363	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Structures and Improvements	$ 1,433,197	$ -	$ -	$ -	$ 1,433,197	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Station Equipment	$ 74,831,146	$ -	$ -	$ -	$ 74,831,146	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Poles, Towers and Fixtures	$ 41,053,494	$ -	$ -	$ -	$ -	$ -	$ 30,790,121	$ 10,263,374	$ -	$ -	$ -	$ -	$ -	$ -
Overhead Conductors and Devices	$ 60,560,377	$ -	$ -	$ -	$ -	$ -	$ 45,420,283	$ 15,140,094	$ -	$ -	$ -	$ -	$ -	$ -
Underground Conduit	$ 22,266,734	$ -	$ -	$ -	$ -	$ -	$ 16,700,051	$ 5,566,684	$ -	$ -	$ -	$ -	$ -	$ -
Underground Conductors and Devices	$ 41,553,937	$ -	$ -	$ -	$ -	$ -	$ 31,165,453	$ 10,388,484	$ -	$ -	$ -	$ -	$ -	$ -
Line Transformers	$ 45,401,636	$ -	$ -	$ -	$ -	$ 45,401,636	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Services	$ 39,866,502	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 39,866,502	$ -	$ -	$ -	$ -	$ -
Meters	$ 23,361,144	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 23,361,144	$ -	$ -	$ -	$ -
Installations on Customers' Premises	$ 260,633	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 260,633	$ -	$ -	$ -
Street Lighting and Signal Systems	$ 22,417,272	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,417,272	$ -	$ -	$ -
Total Distribution Plant	**$ 373,463,434**	**$ -**	**$ -**	**$ -**	**$ 76,721,705**	**$ 45,401,636**	**$ 124,075,907**	**$ 41,358,636**	**$ 39,866,502**	**$ 23,361,144**	**$ 22,677,905**	**$ -**	**$ -**	**$ -**
Total General Plant	**$ 150,007,093**	**$ 10,502,306**	**$ 71,981,740**	**$ 13,037,181**	**$ 7,938,019**	**$ -**	**$ 19,186,788**	**$ 6,395,596**	**$ -**	**$ 7,581,755**	**$ -**	**$ 13,383,708**	**$ -**	**$ -**
Total Plant in Service	**$ 1,423,894,868**	**$ 10,502,306**	**$ 879,260,074**	**$ 106,183,188**	**$ 84,659,724**	**$ 45,401,636**	**$ 143,262,695**	**$ 47,754,232**	**$ 39,866,502**	**$ 30,942,899**	**$ 22,677,905**	**$ 13,383,708**	**$ -**	**$ -**

Table 4-4: Summary of Functionalization and Classification of Test Year Revenue Requirements

Functionalization and Classification of Test Year Revenue Requirements														
Description	Total Revenue Requirement	Production		Transmission	Distribution						Customer			Direct
		Energy	Demand	Demand	Demand				Customer		Customer			Direct
					Substations	Transformers	Lines Prim	Lines Sec	Services	Meters	Lighting	Cust Accounts	Base Rev	
Production Plant Expenses	$ 40,065,184	$ 7,759,491	$ 32,305,693	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Plant Expenses	$ 4,480,554	$ -	$ -	$ 4,480,554	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Plant Expenses	$ 24,519,672	$ -	$ -	$ -	$ 2,577,294	$ 38,471	$ 13,772,366	$ 4,590,789	$ 33,781	$ 3,292,526	$ 214,446	$ -	$ -	$ -
Support Services	$ 6,303,166	$ 430,417	$ 2,997,893	$ 555,774	$ 343,009	$ 10,465	$ 814,933	$ 271,644	$ 9,189	$ 316,108	$ 5,227	$ 548,505	$ -	$ -
Customer Accounts Expense	$ 3,514,947	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,514,947	$ -	$ -
Sales Expense	$ 54,825	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 54,825	$ -	$ -
Admin & General Expense	$ 26,295,971	$ 1,686,269	$ 12,958,378	$ 2,254,908	$ 1,407,677	$ 78,785	$ 3,295,973	$ 1,098,658	$ 69,180	$ 1,257,879	$ 39,353	$ 2,148,912	$ -	$ -
Non-ERC Capacity Purchases	$ 4,642,931	$ -	$ 4,642,931	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Debt Service	$ 40,075,717	$ -	$ 31,558,749	$ 1,700,183	$ 1,400,392	$ 828,711	$ 2,264,743	$ 754,914	$ 727,679	$ 426,408	$ 413,937	$ -	$ -	$ -
Cash Financed Capital Projects	$ 23,827,080	$ -	$ 5,665,501	$ 2,856,172	$ 3,347,507	$ 1,980,955	$ 5,413,656	$ 1,804,552	$ 1,739,448	$ 1,019,289	$ -	$ -	$ -	$ -
Other Expenses	$ 6,356,600	$ 41,537	$ 3,477,533	$ 419,962	$ 334,835	$ 179,567	$ 566,614	$ 188,871	$ 157,675	$ 122,381	$ 89,693	$ 52,933	$ -	$ 725,000
Other Revenue	$ (30,516,823)	$ (3,000,000)	$ (21,870,667)	$ -	$ -	$ -	$ (685,328)	$ (228,443)	$ -	$ -	$ -	$ (4,192,671)	$ (539,713)	$ -
Investment Income	$ (138,942)	$ (1,025)	$ (85,797)	$ (10,361)	$ (8,261)	$ (4,430)	$ (13,979)	$ (4,660)	$ (3,890)	$ (3,019)	$ (2,213)	$ (1,306)	$ -	$ -
Total Net Revenue Requirement	**$ 149,480,882**	**$ 6,916,690**	**$ 71,650,213**	**$ 12,257,192**	**$ 9,402,453**	**$ 3,112,524**	**$ 25,428,977**	**$ 8,476,326**	**$ 2,733,061**	**$ 6,431,572**	**$ 760,443**	**$ 2,126,146**	**$ (539,713)**	**$ 725,000**
Margin Adjustment	$ 1,845,443	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,845,443	$ -
Total Cost of Service	**$ 151,326,325**	**$ 6,916,690**	**$ 71,650,213**	**$ 12,257,192**	**$ 9,402,453**	**$ 3,112,524**	**$ 25,428,977**	**$ 8,476,326**	**$ 2,733,061**	**$ 6,431,572**	**$ 760,443**	**$ 2,126,146**	**$ 1,305,730**	**$ 725,000**

4.2 Allocation Factors

1898 & Co. utilized billing history data and projections of future sales and loads to develop a series of allocation factors. The allocation factors were developed based on billing determinants, estimates of the contributions of each rate classification to the BPU's total annual system energy requirements, average monthly coincident system peak demand, and average monthly non-coincident system peak demand. In addition, the total number of customers in each rate category were determined. Ratios were calculated of each class's contribution for each statistic to the corresponding total. These ratios were used as cost allocation factors to allocate each unbundled component of the test year revenue requirement to the rate classes. These allocation factors are presented in Table 4-5 and the basis for their development are provided in the following sections.

4.2.1 Energy Allocation

An energy allocation factor was developed for use in the apportionment of all energy related expenses. Based on the billing data provided, energy sales to each of the BPU's rate classes were determined. The energy sales for each class were factored up to the system level. System losses were assumed to occur between three voltage levels, from power supply to transmission, from transmission voltage to primary distribution voltage, and from primary distribution voltage to secondary distribution voltage. For example, residential customers incur losses across all three levels while primary service customers do not incur secondary losses. The ratios of the resulting estimated contributions of each class to the total system energy requirements represented the energy allocation factor.

4.2.2 Demand Allocation

The determination of system demand contributions for each rate class required a more complex process. 1898 & Co. used previous experience with similar utilities, regional benchmarking, and metered billing data in order to develop annual load factors for each customer class. Average demand, coincident peak demand (CP), non-coincident peak demand (NCP), excess demand, and average and excess demand (AED) estimates were calculated based on energy sales data and prior utility experience. Consistent with prior BPU rate cases, we use the AED methodology for allocating production demand and transmission expenses.

For each class, maximum demands were estimated based on load factors. The load factors were applied to the corresponding test year energy sales for each class to determine the coincident and non-coincident peaks for each class. Ratios of each class's peak demands to the total for all classes were calculated. These ratios represent the factors to be used in allocating system CP and NCP demand costs among the various rate classes. An NCP allocation factor is used to allocate distribution demand costs.

4.2.3 Customer Allocation

Customer allocation factors were developed to allocate the costs of metering, billing, distribution customer costs, and other administrative costs to the various rate classifications. Customer allocation factors were based on relative weighting of the number of customers included in each rate class served by BPU. Relative weights were estimated to reflect differences in the effort required and the cost incurred to provide customer services to customers in the different rate classes.

Table 4-5: Summary of Class Allocation Factors

Allocation Factor	Total	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	USD 500	Private Area Lighting	KCK	BPU Interdepartmental
Energy Sales @ Meter	100.0%	26.2%	8.5%	21.3%	9.1%	28.8%	2.7%	0.3%	1.8%	1.2%
Energy Sales @ Generation	100.0%	26.6%	8.7%	21.6%	9.1%	27.9%	2.7%	0.4%	1.8%	1.2%
System AED	100.0%	31.4%	10.2%	22.9%	8.1%	20.6%	3.2%	0.3%	2.0%	1.2%
System CP	100.0%	35.3%	9.2%	20.8%	8.0%	19.8%	3.6%	0.2%	1.8%	1.3%
Secondary CP	100.0%	45.6%	11.8%	25.9%	7.0%	1.0%	4.4%	0.2%	2.3%	1.7%
Primary CP	100.0%	41.4%	13.4%	28.7%	7.0%	1.0%	4.0%	0.4%	2.6%	1.5%
Transmission CP	100.0%	35.3%	9.2%	20.8%	8.0%	19.8%	3.6%	0.2%	1.8%	1.3%
System NCP	100.0%	32.2%	10.5%	23.2%	8.0%	19.3%	3.2%	0.3%	2.0%	1.2%
Primary NCP	100.0%	34.6%	11.3%	25.0%	8.6%	13.3%	3.5%	0.4%	2.2%	1.3%
Secondary NCP	100.0%	41.4%	13.4%	28.7%	7.0%	1.0%	4.0%	0.4%	2.6%	1.5%
Number of Customers	100.0%	82.5%	8.2%	0.7%	0.0%	0.0%	0.1%	8.0%	0.5%	0.0%
Meter Reading	100.0%	89.7%	8.9%	0.7%	0.0%	0.0%	0.1%	0.0%	0.5%	0.0%
Records & Billing	100.0%	85.7%	8.5%	1.4%	0.1%	0.0%	0.1%	4.2%	0.0%	0.0%
Weighted Customers	100.0%	76.0%	15.1%	3.1%	0.3%	0.3%	1.1%	3.7%	0.4%	0.0%
Distribution Services	100.0%	85.2%	12.7%	1.3%	0.1%	0.0%	0.2%	0.0%	0.5%	0.0%
Distribution Metering	100.0%	88.3%	8.8%	1.4%	0.2%	0.1%	0.6%	0.0%	0.5%	0.0%
Lighting	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%
Direct Residential	100.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Direct LGS/LPS	100.0%	0.0%	0.0%	0.0%	29.7%	70.3%	0.0%	0.0%	0.0%	0.0%
Net Revenue Requirement	100.0%	38.1%	10.4%	20.1%	7.1%	17.6%	2.8%	1.1%	1.8%	1.0%
Base Rate Revenue	100.0%	36.0%	11.7%	21.6%	7.8%	18.5%	2.9%	1.1%	0.0%	0.3%

Meter reading customer costs were allocated based on the number of customers in each class and were equally weighted. Records and billing customer costs were weighted on a per customer basis with larger customers receiving a higher weighting than residential customers to reflect differences in the effort required. Total customers and distribution metering were weighted on a similar scale with residential customers receiving a lower weighting adjustment than the larger customer classes such as large general service. Secondary distribution customer costs were allocated based on the number of customers served at secondary voltages in each class.

4.3 Cost of Service Summary

Each component item of the FY 2023 test year revenue requirement, which was classified and assigned to the various functional utility services, was allocated to the appropriate customer rate classifications using the corresponding allocation factors described previously. The allocated amounts were summarized for each rate class. The total amounts for each unbundled service within each component of the test year revenue requirement were carried forward from Table 4-2.

Table 4-6 provides a high level summary of each rate class and their corresponding cost of service. An adjustment was made to allocate class deficiencies from the KCK and BPU Interdepartmental classes to the retail classes as the UG (KCK) rate class does not pay their bill and the BPU Interdepartmental rate class does not pay at full retail rates. The adjusted class cost of service shows the required revenue from each class to recover their costs in the 2023 test year. The results show that the Residential class is under-recovering its allocated cost of service under current rates. Conversely, the commercial and industrial classes are recovering more cost than has been allocated, therefore, subsidizing the cost of some other classes.

Table 4-6: Cost of Service Summary by Rate Class

	Total System	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	USD 500	Private Area Lighting	KCK	BPU Interdepartmental
Cost of Service Summary										
Revenue Requirement	$ 151,326,325	$ 57,714,955	$ 15,766,386	$ 30,367,093	$ 10,718,146	$ 26,614,713	$ 4,285,166	$ 1,616,531	$ 2,686,724	$ 1,556,611
Revenue from Current Rates	$ 147,635,439	$ 53,092,238	$ 17,308,307	$ 31,960,311	$ 11,559,431	$ 27,320,996	$ 4,295,902	$ 1,596,941	$ -	$ 501,312
Class Deficiency	$ 3,690,886	$ 4,622,717	$ (1,541,922)	$ (1,593,218)	$ (841,285)	$ (706,283)	$ (10,736)	$ 19,590	$ 2,686,724	$ 1,055,299
Adjustment for KCK and BPU Deficiency	$ -	$ 1,468,359	$ 401,122	$ 772,587	$ 272,687	$ 677,120	$ 109,021	$ 41,127	$ (2,686,724)	$ (1,055,299)
Adjusted Class Cost of Service	$ 151,326,325	$ 59,183,315	$ 16,167,507	$ 31,139,680	$ 10,990,832	$ 27,291,833	$ 4,394,188	$ 1,657,658	$ -	$ 501,312
Indicated % Adjustment	**2.50%**	**11.47%**	**-6.59%**	**-2.57%**	**-4.92%**	**-0.11%**	**2.29%**	**3.80%**		
Energy Sales (kWh)	2,222,687,617	583,000,000	190,000,000	474,000,000	202,000,000	640,000,000	59,000,000	7,713,967	40,021,402	26,952,248
Rev. Requirement - $/kWh	$ 0.0681	$ 0.1015	$ 0.0851	$ 0.0657	$ 0.0544	$ 0.0426	$ 0.0745	$ 0.2149	$ -	$ 0.0186
Rev. from Current Rates	$ 0.0664	$ 0.0911	$ 0.0911	$ 0.0674	$ 0.0572	$ 0.0427	$ 0.0728	$ 0.2070	$ -	$ 0.0186
Difference	$ 0.0017	$ 0.0104	$ (0.0060)	$ (0.0017)	$ (0.0028)	$ (0.0000)	$ 0.0017	$ 0.0079	$ -	$ -
Indicated Adjustment	2.50%	11.47%	-6.59%	-2.57%	-4.92%	-0.11%	2.29%	3.80%	0.00%	0.00%

4.3.1 Unit Costs of Service

Another key outcome of a fully unbundled cost of service study is breaking down the unbundled costs into unit costs of service. By dividing the unbundled costs by the applicable billing units, the allocation was based on ($/kWh, $/kW, or $/bill), BPU will gain a better understanding of the underlying components that are built up into a bundled rate design.

Much like the cost of service results in general, the unit costs of service are used as a guideline for appropriate rate design, not a direct application.

Table 4-7 presents the unit costs of service for BPU in two ways. The first section shows the unit costs by functions of production, transmission, distribution, and customer. The second section shows the units cost by classification (energy, demand, or customer). The latter section is the truest, cost-based rate design, if each class was billed only energy related costs in energy charges, full demand costs in demand charges, and all customer related costs in fixed monthly charges.

Table 4-7: Unit Costs of Service

UNIT COSTS OF SERVICE	Total System	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	USD 500	Private Area Lighting	KCK	BPU Interdepartmental
Cost-of-Service Summary										
Total Bills	887,193	731,827	72,794	5,880	272	168	1,020	71,117	4,115	-
Energy Sales (kWh)	2,222,687,617	583,000,000	190,000,000	474,000,000	202,000,000	640,000,000	59,000,000	7,713,967	40,021,402	26,952,248
Billed Demand (kW)	3,465,490	-	332,535	1,283,653	417,437	1,329,564	-	-	102,300	-
Facilities Demand (kW)	4,648,702	-	943,585	1,619,775	488,035	1,597,306				
Costs by Function										
Production	**$ 79,872,632**	**$ 24,869,687**	**$ 8,067,650**	**$ 18,161,673**	**$ 6,532,142**	**$ 16,933,264**	**$ 2,500,981**	**$ 280,748**	**$ 1,576,899**	**$ 949,590**
Monthly Cost Per Consumer	$ 90.03	$ 33.98	$ 110.83	$ 3,088.72	$ 24,015.23	$ 100,793.24	$ 2,451.94	$ 3.95	$ 383.21	$ -
Average Cost per kWh	$ 0.0359	$ 0.0427	$ 0.0425	$ 0.0383	$ 0.0323	$ 0.0265	$ 0.0424	$ 0.0364	$ 0.0394	$ 0.0352
Cost per Billing kW	$ 23.05	$ -	$ 24.26	$ 14.15	$ 15.65	$ 12.74	$ -	$ -	$ 15.41	$ -
Transmission	**$ 12,257,192**	**$ 3,852,094**	**$ 1,255,379**	**$ 2,807,736**	**$ 994,671**	**$ 2,528,595**	**$ 389,771**	**$ 41,484**	**$ 242,520**	**$ 144,942**
Monthly Cost Per Consumer	$ 13.82	$ 5.26	$ 17.25	$ 477.51	$ 3,656.88	$ 15,051.16	$ 382.13	$ 0.58	$ 58.94	$ -
Average Cost per kWh	$ 0.0055	$ 0.0066	$ 0.0066	$ 0.0059	$ 0.0049	$ 0.0040	$ 0.0066	$ 0.0054	$ 0.0061	$ 0.0054
Cost per Billing kW	$ 3.54	$ -	$ 3.78	$ 2.19	$ 2.38	$ 1.90	$ -	$ -	$ 2.37	$ -
Distribution	**$ 46,420,279**	**$ 18,937,031**	**$ 5,350,442**	**$ 9,240,639**	**$ 3,028,973**	**$ 6,793,698**	**$ 1,344,593**	**$ 445,312**	**$ 817,512**	**$ 462,079**
Monthly Cost Per Consumer	$ 52.32	$ 25.88	$ 73.50	$ 1,571.54	$ 11,135.93	$ 40,438.68	$ 1,318.23	$ 6.26	$ 198.67	$ -
Average Cost per kWh	$ 0.0209	$ 0.0325	$ 0.0282	$ 0.0195	$ 0.0150	$ 0.0106	$ 0.0228	$ 0.0577	$ 0.0204	$ 0.0171
Cost per Billing kW	$ 13.40	$ -	$ 16.09	$ 7.20	$ 7.26	$ 5.11	$ -	$ -	$ 7.99	$ -
Customer	**$ 12,051,222**	**$ 9,831,143**	**$ 1,092,915**	**$ 157,045**	**$ 13,706**	**$ 7,809**	**$ 49,822**	**$ 848,987**	**$ 49,793**	**$ -**
Monthly Cost Per Consumer	$ 13.58	$ 13.43	$ 15.01	$ 26.71	$ 50.39	$ 46.48	$ 48.85	$ 11.94	$ 12.10	$ -
Average Cost per kWh	$ 0.0054	$ 0.0169	$ 0.0058	$ 0.0003	$ 0.0001	$ 0.0000	$ 0.0008	$ 0.1101	$ 0.0012	$ -
Direct	**$ 725,000**	**$ 225,000**	**$ -**	**$ -**	**$ 148,654**	**$ 351,346**	**$ -**	**$ -**	**$ -**	**$ -**
Monthly Cost Per Consumer	$ 0.82	$ 0.31	$ -	$ -	$ 546.52	$ 2,091.35	$ -	$ -	$ -	$ -
Average Cost per kWh	$ 0.0003	$ 0.0004	$ -	$ -	$ 0.0007	$ 0.0005	$ -	$ -	$ -	$ -
Total Costs	**$ 151,326,325**	**$ 57,714,955**	**$ 15,766,386**	**$ 30,367,093**	**$ 10,718,146**	**$ 26,614,713**	**$ 4,285,166**	**$ 1,616,531**	**$ 2,686,724**	**$ 1,556,611**
Costs by Classification										
Energy	**$ 8,222,419**	**$ 2,352,020**	**$ 729,252**	**$ 1,748,869**	**$ 717,727**	**$ 2,152,197**	**$ 222,552**	**$ 38,252**	**$ 159,232**	**$ 102,319**
Monthly Cost Per Consumer	$ 9.27	$ 3.21	$ 10.02	$ 297.43	$ 2,638.70	$ 12,810.69	$ 218.19	$ 0.54	$ 38.70	$ -
Average Cost per kWh	$ 0.0037	$ 0.0040	$ 0.0038	$ 0.0037	$ 0.0036	$ 0.0034	$ 0.0038	$ 0.0050	$ 0.0040	$ 0.0038
Cost per Billing kW	$ 2.37	$ -	$ 2.19	$ 1.36	$ 1.72	$ 1.62	$ -	$ -	$ 1.56	$ -
Demand	**$ 121,851,358**	**$ 38,863,702**	**$ 12,662,445**	**$ 28,202,338**	**$ 9,814,112**	**$ 24,073,778**	**$ 3,922,990**	**$ 416,231**	**$ 2,441,470**	**$ 1,454,292**
Monthly Cost Per Consumer	$ 137.34	$ 53.11	$ 173.95	$ 4,796.32	$ 36,081.29	$ 143,296.30	$ 3,846.07	$ 5.85	$ 593.31	$ -
Average Cost per kWh	$ 0.0548	$ 0.0667	$ 0.0666	$ 0.0595	$ 0.0486	$ 0.0376	$ 0.0665	$ 0.0540	$ 0.0610	$ 0.0540
Cost per Billing kW	$ 35.16	$ -	$ 38.08	$ 21.97	$ 23.51	$ 18.11	$ -	$ -	$ 23.87	$ -
Customer	**$ 20,527,548**	**$ 16,274,233**	**$ 2,374,688**	**$ 415,886**	**$ 37,654**	**$ 37,391**	**$ 139,624**	**$ 1,162,048**	**$ 86,022**	**$ -**
Monthly Cost Per Consumer	$ 23.14	$ 22.24	$ 32.62	$ 70.73	$ 138.43	$ 222.57	$ 136.89	$ 16.34	$ 20.90	$ -
Average Cost per kWh	$ 0.0092	$ 0.0279	$ 0.0125	$ 0.0009	$ 0.0002	$ 0.0001	$ 0.0024	$ 0.1506	$ 0.0021	$ -
Cost per Billing kW	$ 5.92	$ -	$ 7.14	$ 0.32	$ 0.09	$ 0.03	$ -	$ -	$ 0.84	$ -
Direct	**$ 725,000**	**$ 225,000**	**$ -**	**$ -**	**$ 148,654**	**$ 351,346**	**$ -**	**$ -**	**$ -**	**$ -**
Monthly Cost Per Consumer	$ 0.82	$ 0.31	$ -	$ -	$ 546.52	$ 2,091.35	$ -	$ -	$ -	$ -
Average Cost per kWh	$ 0.0003	$ 0.0004	$ -	$ -	$ 0.0007	$ 0.0005	$ -	$ -	$ -	$ -
Cost per Billing kW	$ 0.21	$ -	$ -	$ -	$ 0.36	$ 0.26	$ -	$ -	$ -	$ -
Total Costs	**$ 151,326,325**	**$ 57,714,955**	**$ 15,766,386**	**$ 30,367,093**	**$ 10,718,146**	**$ 26,614,713**	**$ 4,285,166**	**$ 1,616,531**	**$ 2,686,724**	**$ 1,556,611**

5.0 RATE DESIGN

5.1 Rate Design Theory

A number of rate design principles or objectives find broad acceptance in regulatory and policy literature. These include:

1) Efficiency
2) Cost of Service
3) Value of Service
4) Stability
5) Non-Discrimination
6) Administrative Simplicity
7) Balanced Budget

These rate design principles draw heavily on the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates. Each of these principles plays an important role in analyzing the rate proposals developed in this section. To understand the role these principles play, the following discusses each of the principles.

The principle of efficiency broadly incorporates both economic and technical efficiency. As such, this principle has both a pricing dimension and an engineering dimension. Economically efficient pricing promotes good decision-making by electric producers and consumers, fosters efficient expansion of production and delivery capacity, results in efficient capital investment in customer facilities and facilitates the efficient use of existing electric supply and delivery resources. The efficiency principle benefits stakeholders by creating outcomes for regulation consistent with the long-run benefits of competition while permitting the economies of scale consistent with the best cost of service. Technical efficiency means that the development of the system is designed and constructed to meet the peak load requirements of customers using the most economic equipment and technology to deliver low cost energy. Efficiency recognizes that load diversity increases as the facilities move further away from the customer.

The principles of cost of service and value of service each relate to designing rates that recover the total revenue requirement without causing inefficient choices by consumers. The cost of service principle contrasts with the value of service principle when certain transactions do not occur at price levels determined by embedded cost of service. In essence, the value of service acts as a ceiling on prices. Where prices are set at levels higher than the value of service, consumers will not purchase the service.

The calculation of a "true" cost of service is complicated by the fact that for network industries like the electric industry, the provision of public utility service often involves joint and common costs which must be allocated (rather than directly assigned) to specific customer classes or rate schedules to develop a full cost of service study. While a good fully distributed cost of service analysis can be performed using principles of cost causation, informed judgment is nonetheless required to perform such a study. A fully distributed cost of service study, properly reflecting cost causation principles and employing sound methods, provides a reasonable tool for the allocation of the total revenue requirement to customer classes (interclass distribution) and within the customer classes (intraclass distribution).

The principle of stability typically applies to customer rates. This principle suggests that reasonably stable and predictable prices are important objectives of a proper rate design. This principle also means avoiding unreasonable changes in bills resulting from redesigning rates.

The concept of non-discrimination requires prices designed to promote fairness and avoid undue discrimination. Fairness requires no undue subsidization either between customers in the same class or across different classes of customers.

This principle recognizes that the ratemaking process requires discrimination where there are factors at work that cause the discrimination to be useful in accomplishing other objectives. For example, things like the location, type of meter and service, demand characteristics, size, and a variety of other considerations are often recognized in the design of utility rates to properly distribute the total cost of service to and within customer classes.

The principle of administrative simplicity as it relates to rate design requires prices reasonably simple to administer and understand. This concept includes price transparency within the constraints of the ratemaking process. Prices are transparent when customers are able to reasonably calculate and predict bill levels and interpret details about the charges resulting from the application of the tariff.

Finally, there is the critical principle that rate design permits the utility a reasonable opportunity to recover the approved revenue requirement based on the cost of service. This is the principle of a balanced budget. Proper design of utility rates is a necessary condition to enable an effective opportunity to recover the cost of providing service included in the revenue authorized by the regulatory authority. This principle is very similar to the stability objective previously discussed from the perspective of customer rates.

At times these principles, like most principles that have broad application, can compete with each other. This competition or tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design alternatives and rate design recommendations must recognize the potential and actual competition between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. For example, as noted above, there are tensions between cost and value of service principles.

The conflict between good price signals based on marginal cost and a balanced budget or revenue recovery principle arises because marginal cost is below average cost due to economies of scale. Where fixed delivery service costs do not vary with kilowatt-hours sold, marginal costs for delivery equal zero. Marginal customer costs equal the additional cost of providing the entire delivery service to the customer. Marginal cost tends to be either above or below average cost in both the short run and the long run. This means that marginal cost-based pricing will produce either too much or too little revenue to support the revenue requirement. This suggests that efficient price signals may require a multi-part tariff designed to meet the revenue requirements while sending marginal cost price signals related to consumption decisions. Properly designed, a multi-part tariff may include elements such as customer charges, facilities demand charges, demand charges, consumption charges and the potential for revenue credits. For residential and small general service customers, the combination of an customer charge and seasonally differentiated kilowatt-hour charges are sufficient elements of the multi-part rate. For larger customers, a combination of these elements permits good price signals and revenue recovery; however, the tariff design becomes more difficult to structure and likely will no longer meet the requirements of simplicity. Therefore, sacrificing some economic efficiency for a customer class in order to maintain simplicity represents a reasonable compromise. For larger customers, the added complexity of a demand charge is not a concern.

There are potential conflicts between simplicity and non-discrimination and between value of service and non-discrimination. Other potential conflicts arise where companies face unique circumstances that must be considered as part of the rate design process.

The process of developing rates within the context of these principles and conflicts requires a detailed understanding of all the factors that impact rate design. These factors include:

1) System cost characteristics such as the embedded customer, demand, and energy related costs by type of service.

2) Customer load characteristics such as peak demand, load factor, seasonality of loads, and quality of service.

3) Market considerations such as elasticity of demand, competitive fuel prices and end-use load characteristics.

4) Other considerations such as the value of service ceiling/marginal cost floor, unique customer requirements, areas of under-utilized facilities, opportunities to offer new services and the status of competitive market development.

In addition, the development of rates must consider existing rates and the customer impact of modification to the rates.

In each case, a rate design seeks to recover the authorized level of revenue based on the actual billing determinants occurring during the test period used to develop the rates. Critical to the rate making process is the requirement that the rates based on the test year provide an opportunity for the utility to recover its approved costs in the "rate effective period," which is typically the first twelve months after the new rates take effect.

5.2 Recommended Rate Design

In practice, rates must be redesigned to recover the target revenues during the rate effective period. The design or rates includes not only the determination of the rate elements but also various rate provisions. Appendix B provides a revised Rate Application Manual. Recommended changes to the Rate Application Manual include the following:

- Merging of the standard Residential and Residential Electric Heat classes into one residential class that reflects the rate design of the current residential electric heating rate.

- Continuing the trend of increasing the Customer Charge to reflect cost of service and recovery of more fixed costs through fixed charges.

- Modifying the ERC rider to allow for additional recovery over costs to build and maintain an ERC Reserve fund.
- Creation of a Green Rider for customers that want to procure energy with renewable attributes.
- Other language changes within the Rate Manual to align the language with current BPU practice.

Each of these changes has been designed to clarify billing provisions identified by BPU staff or to improve the accuracy of rate mechanisms.

Table 5-1: Rate Component Descriptions

Typical Bill Charges	Description
Customer Charge	Provides for a recovery of costs incurred in providing service to customers. Represents a portion of the cost of system access and customer service including the cost of meter reading, bill calculation, postage and the expenses associated with the basic plant investment at each service location, such as meters, transformers, service lines, etc.
Facilities Charge	Recovers capital costs and related expenses associated with distributing electricity from the Utility's substation to the customer's service conductor (or for primary service to the customer's transformer).
Demand Charge	Applied to a customer's billing demand expressed in Kilowatts (kW). Primarily for recovery of production and transmission costs.
Energy Charge	Applied to the amount of energy used by a customer, expressed in Kilowatt-hours (kWh). Recovers variable costs plus fixed costs not recovered in demand or customer charges.
ERC Rider	Applied to the amount of energy used by a customer to recover the Utility's fuel and all purchased power and chemical costs and other ancillary costs incurred to provide energy to customers.
ESC Rider	Provides for the annual debt service recovery of the Utility's capital investment in projects that are required to meet Federal, State, or Local environmental regulations.

5.2.1 Target Class Revenue Adjustments

The rate design process begins with a review of the class cost of service results. For classes with indicated increases larger than the system average, a larger percentage increase has been proposed. This mainly lies with the residential class, which shows the need for the highest adjustment. For classes recovering more than the indicated cost of service or are near their cost of service, a lower increase has been proposed. In each case the proposed increase is a target, and the actual increase will be slightly different. The process of rounding and truncating rate elements always causes slight deviations from target revenue. As long as these differences are small it is reasonable to consider them immaterial.

Using the results of the cost of service study as a guideline, Table 5-2 presents the recommended class adjustments for each rate class for 2023 and 2024. The COS study indicates that the Residential class is under recovering its allocated costs by more than any other class. The SGS, MGS, and LGS classes are all over recovering their respective cost to serve. As such, we proposed that the Residential class receive more than the system average increase and the commercial and industrial classes receive less than the system average increase. We capped the maximum increase for any class at 150% of the system average, which results in a 3.75% increase for the residential class. The commercial and industrial classes receive less than the system average based on the lowest percentage that still allows the system to recover an overall increase of 2.50%.

Table 5-2: Target Class Base Revenue Adjustments

Base Rate Summary		
Class	**2023**	**2024**
Residential	3.75%	3.75%
Small General Service	1.75%	1.73%
Medium General Service	1.75%	1.73%
Large General Service	1.75%	1.73%
Large Power Service	1.75%	1.73%
USD 500	2.50%	2.50%
Private Area Lighting	2.50%	2.50%
BPU Interdepartmental	2.50%	2.50%

As the table illustrates, the increases are designed to move the various rate classes toward cost of service over time while avoiding disruptively large increases relative to the 2.50% increases in 2023 and 2024.

5.2.2 Residential Rate Design

The residential rate class is under recovering its cost of service. Based on this under recovery, we propose to increase the class at a rate higher than the system average (2.50%) in the next two years. The proposed changes to the residential base rate design reflect the reflect a 3.75% increase in base rates in both years (Table 5-2). We are also proposing to merge the standard residential rate and residential heating rate beginning in 2023.

The Customer Charge is designed to recover the fixed costs incurred to allow the customer to access and use power from the system. As nearly all costs that are recovered in base rates are fixed, we propose to put the majority of the increase in the Customer Charge to better reflect cost causation.

With respect to changes to the Customer Charge, one concern is for the impact on low income customers. This concern is usually expressed related to the bill impact on low use bills. First, low use bills are not the same as bills for low income customers. In fact, based on data for low income residential customers as identified through customers participating in the LIHEAP program, low income customers use more power than the average customer. This leads to a second point, namely, low income customers on average have a lower bill impact than the average customer. This occurs because the more cost recovered in the Customer Charge, the lesser the impact on the kWh charges in the rate. As customers use power above the average, the increase is proportionally lower.

The proposed energy charge portion of the residential rate merges the standard and electric heating rates together beginning in 2023 into the general design of the current electric heating rate. For the summer months of June – September, there is one single flat rate, The proposed energy charge for the remaining winter months consists of two blocks, with a lower rate for usage above 1,000 kWh to promote electric heating and benefit customers utilizing high levels of electric heat. Table 5-3 illustrates the current and the proposed charges for 2023 and 2024.

Table 5-3: Residential Rate Design

DESCRIPTION	PRESENT RATE	RECOMMENDED RATE 2023	RECOMMENDED RATE 2024
100 - Residential			
Customer Charge	$ 22.00	$ 24.00	$ 26.00
Energy Charge			
First 1000 kWh			
Summer	$ 0.06466	$ 0.06911	$ 0.06923
Winter	$ 0.06466	$ 0.06650	$ 0.06850
All Additional kWh			
Summer	$ 0.06466	$ 0.06911	$ 0.06923
Winter	$ 0.06466	$ 0.03750	$ 0.03800

The following Table 5-4 shows the impact on monthly residential bills for 2023 using examples of common usage amounts for summer and winter months. Monthly bills are calculated, including ERC and ESC charges at their current rates to show the overall impact on customers' bills, while PILOT has been excluded from the calculation. In general, customers with higher usage rates will see lower increases due to the majority of the increase occurring in the fixed customer charge, most notably in the winter months.

Table 5-4: Residential Bill Impacts

RATE CLASS	ENERGY USAGE	EXISTING BILL(1)	RECOMMENDED		
			BILL(1)	INCREASE	INCREASE
	kWh	$	$	$	%
Monthly					
100 - Residential - Winter	500	$ 82.35	$ 85.27	2.92	3.5%
100 - Residential - Winter	750	$ 112.52	$ 115.90	3.38	3.0%
100 - Residential - Winter	1,000	$ 142.69	$ 146.53	3.84	2.7%
100 - Residential - Winter	1,500	$ 203.04	$ 193.30	(9.74)	-4.8%
100 - Residential - Winter	500	$ 76.87	$ 79.79	2.92	3.8%
100 - Residential - Winter	750	$ 104.30	$ 107.68	3.38	3.2%
100 - Residential - Winter	1,000	$ 131.73	$ 135.57	3.84	2.9%
100 - Residential - Winter	1,500	$ 186.60	$ 176.86	(9.74)	-5.2%
100 - Residential - Summer	750	$ 105.69	$ 111.03	5.34	5.1%
100 - Residential - Summer	1,000	$ 133.59	$ 140.04	6.45	4.8%
100 - Residential - Summer	1,500	$ 189.39	$ 198.06	8.68	4.6%
100 - Residential - Summer	2,000	$ 245.18	$ 256.08	10.90	4.4%
100 - Residential - Summer	2,500	$ 300.98	$ 314.10	13.13	4.4%
100 - Residential - Summer	750	$ 111.78	$ 117.11	5.34	4.8%
100 - Residential - Summer	1,000	$ 141.70	$ 148.15	6.45	4.6%
100 - Residential - Summer	1,500	$ 201.55	$ 210.23	8.68	4.3%
100 - Residential - Summer	2,000	$ 261.40	$ 272.30	10.90	4.2%
100 - Residential - Summer	2,500	$ 321.25	$ 334.38	13.13	4.1%
Total Residental Base Revenue Under Existing rates		$ 53,092,246			
Total Residental Base Revenue Under Recommended rates		$ 55,083,019			
Recommended First Year Increase		$ 1,990,773			
Total Number of Bills		731,827			
Average Increase per Bill per Month		$ 2.72			

5.2.3 Small General Service Class – Rate 200

The Small General Service (SGS) Class cost of service indicates an over recovery of 6.6%. As a result, we have proposed a lower than system average percentage increase of 1.75% in 2023 and 1.73% in 2024 as shown in Table 5-2. The proposed Customer Charge is $42.00 per month in 2023 and $44.00 per month in 2024.

The Facilities Charges have been directionally increased to recover distribution demand costs guided by the unit costs in the cost of service study. The billed demand charge has slightly increased as well as the rate component changes take effect in the fixed costs portion of the monthly bill. The energy charge block will remain a singular flat charge for all kWh and increase slightly in each of the next two years.

The electric heating rate will continue to have the same customer and facilities demand charges with a declining block energy charge in the winter months to provide an incentive to customers with higher winter heating loads. In addition, the calculation for billed demand units remains unchanged. The recommended Small General Service rates are shown in Table 5-5.

Table 5-5: Small General Service Rate Design

DESCRIPTION	PRESENT RATE	RECOMMENDED RATE 2023	RECOMMENDED RATE 2024
200 - Small General Service			
Customer Charge	$ 40.00	$ 42.00	$ 44.00
Facilities Charge			
Secondary Service	$ 3.30	$ 3.38	$ 3.45
Primary Service	$ 2.65	$ 2.74	$ 2.80
Demand Charge			
First 10 kW	$ -	$ -	$ -
All additional kW	$ 5.57	$ 5.75	$ 5.90
Energy Charge			
All kWh	$ 0.04733	$ 0.04746	$ 0.04771
200ND - SGS Non-Demand			
Customer Charge	$ 40.00	$ 42.00	$ 44.00
Energy Charge			
All kWh	$ 0.08846	$ 0.08850	$ 0.08850
201 - Small General Service Electric Heating			
Same Customer and Demand Charges as above			
Energy Charge			
First 3500 kWh	$ 0.04733	$ 0.04746	$ 0.04771
All Additional kWh			
Summer	$ 0.04733	$ 0.04746	$ 0.04771
Winter	$ 0.02709	$ 0.02712	$ 0.02712

5.2.4 Medium General Service Class – Rate 250

The Medium General Service (MGS) rate class indicates a slight over recovery (2.6%) in cost of service. As a result, we have proposed a lower than system average percentage increase of 1.75% in 2023 and 1.73% in 2024 as shown in Table 5-2. The proposed Customer Charge is $90.00 per month in 2023 and $95.00 per month in 2024.

The facilities demand charges have been increased to recover distribution demand costs guided by the unit costs in the cost of service study. The billed demand charge has slightly increased as well as the rate component changes mainly take effect in the fixed costs portion of the monthly bill. The energy charge blocks will continue to use an hours use of demand rate design with a block for the first 300 kWh per kW and one for all additional kWh.

The electric heating rate structure will remain the same with a different basis for calculating billed demand and a lower second block energy charge in the winter period.

Table 5-6: Medium General Service Rate Design

DESCRIPTION	PRESENT RATE	RECOMMENDED RATE 2023	RECOMMENDED RATE 2024
250 - Medium General Service			
Customer Charge	$ 85.00	$ 90.00	$ 95.00
Facilities Charge			
Secondary Service	$ 4.11	$ 4.22	$ 4.34
Primary Service	$ 3.54	$ 3.65	$ 3.75
Demand Charge			
All kW	$ 6.66	$ 6.88	$ 7.10
Energy Charge			
First 300 kWh per kW	$ 0.03724	$ 0.03739	$ 0.03751
All Additional kWh	$ 0.02188	$ 0.02201	$ 0.02216
251 - Medium General Service Electric Heating			
Same Customer and Demand Charges as above			
Energy Charge			
First 300 kWh per kW	$ 0.03724	$ 0.03739	$ 0.03751
All Additional kWh			
Summer	$ 0.02188	$ 0.02201	$ 0.02216
Winter	$ 0.01164	$ 0.01177	$ 0.01177

5.2.5 Large General Service Class – Rate 300

The Large General Service (LGS) class cost of service indicates an over recovery in cost of service by 4.9%. As a result, we have proposed a lower than system average percentage increase in accordance with both the SGS and MGS rate classes. The 2023 and 2024 increase targets are 1.75% and 1.73% respectively. The proposed Customer Charge is $180.00 per month in 2023 and $190.00 per month in 2024.

The increase in the facilities demand charge and the base demand charge are based on cost of service principles. The energy charge blocks will remain the same structurally, with two blocks for the first 300 kWh per kW, and all additional kWh.

The electric heating rate structure will remain the same with a lower second block energy charge in the winter period, benefiting customers with higher winter electric heating loads.

Table 5-7: Large General Service Rate Design

DESCRIPTION	PRESENT RATE	RECOMMENDED RATE	
		2023	2024
300 - Large General Service			
Customer Charge	$ 170.00	$ 180.00	$ 190.00
Facilities Charge			
Secondary Service	$ 4.13	$ 4.26	$ 4.38
Primary Service	$ 3.56	$ 3.68	$ 3.80
Demand Charge			
All kW	$ 8.66	$ 8.90	$ 9.18
Energy Charge			
First 300 kWh per kW	$ 0.03636	$ 0.03661	$ 0.03679
All Additional kWh	$ 0.01582	$ 0.01591	$ 0.01595
301 - Large General Service Electric Heating			
Same Customer and Demand Charges as above			
Energy Charge			
First 300 kWh per kW	$ 0.03636	$ 0.03661	$ 0.03679
All Additional kWh			
Summer	$ 0.00555	$ 0.01591	$ 0.01595
Winter	$ 0.00555	$ 0.00555	$ 0.00555

5.2.6 Large Power Service Class – Rate 400

The Large Power Service (LPS) class cost of service indicates slight over recovery of cost of service relative to the system average (-0.1% vs 2.5%). As a result, we have proposed a lower than system average percentage increase of 1.75% in 2023 and 1.73% in 2024 as shown in Table 5-2. The proposed Customer Charge is $420.00 per month in 2023 and $440.00 per month in 2024.

All rate components have been increased slightly to meet the overall class revenue target.

The electric heating rate structure will remain the same with a lower second block energy charge in the winter period, benefiting customers with higher winter electric heating loads. The billed demand charge is now set equal to the standard LPS billed demand charge, like all other electric heating classes with demand charges. This increase is offset with a 38% decrease to the second block energy charge in the winter.

Table 5-8: Large Power Service Rate Design

DESCRIPTION	PRESENT RATE	RECOMMENDED RATE	
		2023	2024
400 - Large Power Service			
Customer Charge	$ 400.00	$ 420.00	$ 440.00
Facilities Charge			
Secondary Service	$ 3.40	$ 3.50	$ 3.60
Primary Service	$ 2.88	$ 2.95	$ 3.04
Substation Service	$ 1.00	$ 1.03	$ 1.06
Demand Charge			
All kW	$ 9.71	$ 9.90	$ 10.20
Energy Charge			
First 300 kWh per kW	$ 0.02183	$ 0.02211	$ 0.02211
All Additional kWh	$ 0.01101	$ 0.01099	$ 0.01089
401 - Large Power Service - Electric Heating			
Same Customer and Facilities Demand Charges as above			
Demand Charge			
All kW	$ 8.56	$ 9.90	$ 10.20
Energy Charge			
First 300 kWh per kW	$ 0.02183	$ 0.02211	$ 0.02211
All Additional kWh			
Summer	$ 0.01101	$ 0.01099	$ 0.01089
Winter	$ 0.00577	$ 0.00360	$ 0.00363
450 - Large Power High Load Factor			
Customer Charge	$ 400.00	$ 420.00	$ 440.00
Facilities Charge			
Secondary Service	$ 3.40	$ 3.50	$ 3.60
Primary Service	$ 2.88	$ 2.95	$ 3.04
Substation Service	$ 1.00	$ 1.03	$ 1.06
Demand Charge			
All kW	$ 17.93	$ 18.11	$ 18.29

5.2.7 Unified School District 500 and Lighting Classes

The School District is currently under recovering their allocated cost of service by 2.29%, which is roughly the system average. The contract rate is an energy only rate and we recommend a 2.50% increase in 2023 and a 2.50% increase in 2024.

The lighting class is currently under recovering its cost of service by 3.8% and has been assigned a 2.50% increase in both 2023 and 2024. Each current lighting rate or charge will be increased by the same percentage. In addition, we have created four new lighting rates for LED light fixtures that will be added to the rate manual.

5.2.8 UG Municipal and BPU Interdepartmental Rates

Currently all electric accounts of the UG are tracked like a normal commercial customer, but bills are not rendered to UG accounts, and they do not pay for electric service. This results in all other customers paying higher rates to make up for the lost revenue from UG accounts. While it is not unique for municipal accounts to not pay for electric service, the UG situation is compounded by the UG charging a very high PILOT of 11.9%. While the BPU has taken many steps to control costs in an effort to keep rates low and attract new customers, they have no control over the PILOT rate, which negatively impacts the BPU's competitiveness with surrounding utilities.

5.2.8.1 BPU Community Contributions

The combined amount that BPU ratepayers contribute to the UG includes primarily the PILOT payment and the value of free electric service not billed to the UG. These costs are shown below in Table 5-9. The PILOT payment ranges from $30.7 million to $37.5 million annually in addition to unbilled electric services valued at $4.9 million annually. In addition to these contributions, the BPU also provides street light maintenance, free water service, fire hydrant services, and billing services to the UG, the value of which was an additional $3.1 million in 2022.

Table 5-9: BPU Community Contributions to UG

BPU Community Contributions Funded by Ratepayers					
Description	**2023**	**2024**	**2025**	**2026**	**2027**
Payment in Lieu of Taxes	$ 30,701,836	$ 31,059,724	$ 31,566,934	$ 32,245,618	$ 32,542,690
UG Base Rates Not Billed	$ 2,960,577	$ 2,966,025	$ 2,971,483	$ 2,976,952	$ 2,982,432
UG ERC and ESC Riders not Billed	$ 1,906,696	$ 1,941,554	$ 1,962,537	$ 1,997,120	$ 1,942,682
Total Free Electric Service	$ 4,867,274	$ 4,907,579	$ 4,934,020	$ 4,974,072	$ 4,925,114
Total Community Contribution	**$ 35,569,110**	**$ 35,967,302**	**$ 36,500,953**	**$ 37,219,690**	**$ 37,467,804**

In order to improve equity for all residents and businesses in KCK, 1898 & Co. recommends the BPU begin charging the UG for electric service.

For internal BPU accounts, such as offices and the Water Treatment Plant, the BPU currently charges a rate of $0.0186/kWh with no additional riders. This is obviously well below the cost to serve these loads. We recommend at a minimum that BPU Interdepartmental load be also charged the ERC rider, as well as a 2.5% increase to its base energy charge.

5.3 Riders and Other Rate Manual Changes

In addition to language updates to existing riders, 1898 & Co. is proposing a new rider for the Rate Manual: A Green Rider for the procurement of energy with renewable attributes.

5.3.1 Energy Rate Component Rider (ERC)

The BPU's current rate manual includes an Energy Rate Component rider. The purpose of this rider is to provide for recovery of the Utility's power supply costs not recovered in the base monthly charges, with a reconciliation adjustment that provides for the treatment of over/under recoveries for each quarter period.

As discussed in Section 3.3.3, 1898 & Co. has proposed the addition of an ERC Reserve fund to better manage BPU's minimum operating cash levels. Language changes to the ERC rider to allow for this are shown in Appendix B.

5.3.2 Environmental Surcharge Rider (ESC)

Structurally there are no changes in how the ESC is tracked or applied. The ESC is allocated to each class based on the allocation of production demand costs, and these allocations are updated each time there is a rate case. Table 5-10 shows the updated allocations for future charges and the estimated 2023 rates once adopted.

Table 5-10: 2023 ESC Allocations

Rate Class	AED Allocator	Adjusted for Retail	Allocated Cost	2023 Billing Units MWh	2023 Billing Units kW	Charge per Month $/kWh	Charge per Month $/kW-month
Rate 100 - Residential	31.427%	32.569%	$7,123,058	583,000		$ 0.01222	
Rate 200 - Small General Service	10.242%	10.693%	$2,338,630	190,000		$ 0.01231	
Rate 250 - Medium General Servic	22.907%	23.771%	$5,198,876		1,283,653		$ 4.050
Rate 300 - Large General Service	8.115%	8.380%	$1,832,762		417,437		$ 4.391
Rate 400 - Large Power Service	20.629%	21.303%	$4,659,108		1,329,564		$ 3.504
Rate 500 - School District	3.180%	3.284%	$718,233	59,000		$ 0.01217	
Rate 700 - Lighting	0.338%	0.000%	$0				
KCK/BPU	3.161%	0.000%	$0				
	100.000%	100.000%	$21,870,667				

5.3.3 Green Rider

The Green Rider is a new program targeted at large commercial and industrial customers (generally the LGS and LPS rate classes), that allows customers to purchase energy with Environmental Attributes (EA) to meet renewable energy goals. Customers will be eligible to participate in the process to purchase EAs for amounts of not less than 10,000,000 kWh and not more than the customer's annual expected energy usage. The rider applies to customers who wish to achieve environmental sustainability goals by purchasing from BPU exclusive EAs associated with renewable energy that is either from facilities owned by BPU or procured by BPU through a Purchased Power Agreement (PPA).

5.4 Summary of Rate Design

Table 5-11 demonstrates the adequacy of revenues after rate design by customer class for the recommended 2023 and 2024 rates and shows a yearly revenue increase of 2.50%.

Table 5-11: Summary of Class Revenue Under Proposed Rates

Description	2023 Revenue Under 2022 Rates	Revenues Under Proposed Rates	Revenue Change	Revenue % Change	2024 Revenues Under 2023 Rates	Revenues Under Proposed Rates	Revenue Change	Revenue % Change
Base Rate Summary								
Residential	$ 53,092,238	$ 55,083,197	$ 1,990,959	3.75%	$ 55,284,584	$ 57,357,756	$ 2,073,172	3.75%
Small General Service	$ 17,308,307	$ 17,610,705	$ 302,398	1.75%	$ 17,644,789	$ 17,950,015	$ 305,226	1.73%
Medium General Service	$ 31,960,311	$ 32,518,698	$ 558,386	1.75%	$ 32,581,032	$ 33,144,631	$ 563,598	1.73%
Large General Service	$ 11,559,431	$ 11,761,389	$ 201,958	1.75%	$ 11,773,241	$ 11,976,898	$ 203,658	1.73%
Large Power Service	$ 27,320,996	$ 27,798,328	$ 477,332	1.75%	$ 27,729,524	$ 28,209,199	$ 479,675	1.73%
USD 500	$ 4,295,902	$ 4,403,300	$ 107,398	2.50%	$ 4,402,338	$ 4,512,397	$ 110,058	2.50%
Private Area Lighting	$ 1,596,941	$ 1,636,865	$ 39,924	2.50%	$ 1,636,708	$ 1,677,626	$ 40,918	2.50%
Total	**$ 147,134,127**	**$ 150,812,481**	**$ 3,678,353**	**2.50%**	**$ 151,052,216**	**$ 154,828,521**	**$ 3,776,305**	**2.50%**

5.5 Typical Bill Comparison

Table 5-12 through Table 5-16 show a comparison of existing and recommended rates at various usage and demand levels for each retail rate class under the proposed 2023 rates. The bill values shown include both the ERC and ESC riders but exclude PILOT. Winter comparisons include the 4th quarter ERC charge of $0.04597/kWh and summer comparisons include the 3rd quarter ERC of $0.04498/kWh. ESC is included at the 2022 rate for each class.

Table 5-12: Residential Bill Comparison

RATE CLASS	ENERGY USAGE	EXISTING BILL(1)	RECOMMENDED		
			BILL(1)	INCREASE	INCREASE
	kWh	$	$	$	%
Monthly					
100 - Residential - Winter	500	$ 82.35	$ 83.19	0.84	1.0%
100 - Residential - Winter	750	$ 112.52	$ 112.78	0.26	0.2%
100 - Residential - Winter	1,000	$ 142.69	$ 142.37	(0.32)	-0.2%
100 - Residential - Winter	1,500	$ 203.04	$ 201.56	(1.48)	-0.7%
100 - Residential - Summer	750	$ 111.78	$ 117.11	5.34	4.8%
100 - Residential - Summer	1,000	$ 141.70	$ 148.15	6.45	4.6%
100 - Residential - Summer	1,500	$ 201.55	$ 210.23	8.68	4.3%
100 - Residential - Summer	2,000	$ 261.40	$ 272.30	10.90	4.2%
100 - Residential - Summer	2,500	$ 321.25	$ 334.38	13.13	4.1%
Total Residental Base Revenue Under Existing rates		$ 53,092,246			
Total Residental Base Revenue Under Recommended rates		$ 55,083,019			
Recommended First Year Increase		$ 1,990,773			
Total Number of Bills		731,827			
Average Increase per Bill per Month		$ 2.72			

Table 5-13: Small General Service Bill Comparison

RATE CLASS	ENERGY USAGE	EXISTING BILL(1)	RECOMMENDED		
			BILL(1)	INCREASE	INCREASE
	kWh	$	$	$	%
Monthly					
200 - SGS - Secondary - Summer	4,000	$ 556.80	$ 561.72	4.92	0.9%
200 - SGS - Secondary - Summer	6,000	$ 810.05	$ 816.53	6.48	0.8%
200 - SGS - Secondary - Summer	8,000	$ 1,063.30	$ 1,071.34	8.04	0.8%
200 - SGS - Secondary - Summer	12,000	$ 1,541.95	$ 1,552.21	10.26	0.7%
200 - SGS - Secondary - Summer	18,000	$ 2,257.35	$ 2,270.99	13.64	0.6%
200 - SGS - Secondary - Summer	25,000	$ 3,049.35	$ 3,065.60	16.25	0.5%
200 - SGS - Secondary - Winter	4,000	$ 544.13	$ 549.05	4.92	0.9%
200 - SGS - Secondary - Winter	6,000	$ 791.04	$ 797.52	6.48	0.8%
200 - SGS - Secondary - Winter	8,000	$ 1,037.95	$ 1,045.99	8.04	0.8%
200 - SGS - Secondary - Winter	12,000	$ 1,503.93	$ 1,514.19	10.26	0.7%
200 - SGS - Secondary - Winter	18,000	$ 2,277.67	$ 2,293.41	15.74	0.7%
200 - SGS - Secondary - Winter	25,000	$ 3,119.69	$ 3,140.24	20.55	0.7%
200 - SGS - Primary - Summer	3,920	$ 546.46	$ 551.33	4.86	0.9%
200 - SGS - Primary - Summer	5,880	$ 793.54	$ 799.89	6.35	0.8%
200 - SGS - Primary - Summer	7,840	$ 1,041.72	$ 1,049.60	7.88	0.8%
200 - SGS - Primary - Summer	11,760	$ 1,510.80	$ 1,520.86	10.06	0.7%
200 - SGS - Primary - Summer	17,640	$ 2,211.89	$ 2,225.26	13.37	0.6%
200 - SGS - Primary - Summer	24,500	$ 2,988.05	$ 3,003.98	15.93	0.5%
200 - SGS - Primary - Winter	3,920	$ 534.04	$ 538.91	4.86	0.9%
200 - SGS - Primary - Winter	5,880	$ 774.91	$ 781.26	6.35	0.8%
200 - SGS - Primary - Winter	7,840	$ 1,016.88	$ 1,024.76	7.88	0.8%
200 - SGS - Primary - Winter	11,760	$ 1,473.54	$ 1,483.60	10.06	0.7%
200 - SGS - Primary - Winter	17,640	$ 2,231.80	$ 2,247.23	15.43	0.7%
200 - SGS - Primary - Winter	24,500	$ 3,056.98	$ 3,077.13	20.14	0.7%
201 - SGS - Secondary Electric Heat - Summer	4,000	$ 556.80	$ 562.28	5.48	1.0%
201 - SGS - Secondary Electric Heat - Summer	6,000	$ 810.05	$ 815.87	5.82	0.7%
201 - SGS - Secondary Electric Heat - Summer	8,000	$ 1,063.30	$ 1,069.46	6.16	0.6%
201 - SGS - Secondary Electric Heat - Summer	12,000	$ 1,541.95	$ 1,547.89	5.94	0.4%
201 - SGS - Secondary Electric Heat - Summer	18,000	$ 2,257.35	$ 2,263.01	5.66	0.3%
201 - SGS - Secondary Electric Heat - Summer	25,000	$ 3,049.35	$ 3,053.35	4.00	0.1%
201 - SGS - Secondary Electric Heat - Winter	4,000	$ 534.01	$ 536.73	2.72	0.5%
201 - SGS - Secondary Electric Heat - Winter	6,000	$ 740.44	$ 744.46	4.02	0.5%
201 - SGS - Secondary Electric Heat - Winter	8,000	$ 946.87	$ 952.19	5.32	0.6%
201 - SGS - Secondary Electric Heat - Winter	12,000	$ 1,331.89	$ 1,338.91	7.02	0.5%
201 - SGS - Secondary Electric Heat - Winter	18,000	$ 1,956.34	$ 1,967.16	10.82	0.6%
201 - SGS - Secondary Electric Heat - Winter	25,000	$ 2,600.98	$ 2,613.90	12.92	0.5%

Table 5-14: Medium General Service Bill Comparison

RATE CLASS	ENERGY	FACILITY	BILLED DEMAND	EXISTING BILL(1)	RECOMMENDED		
					BILL(1)	INCREASE	INCREASE
	kWh	kW	kW	$	$	$	%
Monthly							
250 - MGS - Secondary - Summer	35,000	150	100	4,278.49	4,327.14	48.65	1.1%
250 - MGS - Secondary - Summer	75,000	300	200	8,765.73	8,858.68	92.95	1.1%
250 - MGS - Secondary - Summer	125,000	500	300	14,045.96	14,190.01	144.05	1.0%
250 - MGS - Secondary - Summer	175,000	700	450	20,086.57	20,293.02	206.45	1.0%
250 - MGS - Secondary - Winter	35,000	150	100	4,451.45	4,500.10	48.65	1.1%
250 - MGS - Secondary - Winter	75,000	300	200	9,136.35	9,229.30	92.95	1.0%
250 - MGS - Secondary - Winter	125,000	500	300	14,663.67	14,807.72	144.05	1.0%
250 - MGS - Secondary - Winter	175,000	700	450	20,951.36	21,157.81	206.45	1.0%
250 - MGS - Primary - Summer	35,000	150	100	4,192.99	4,327.14	134.15	3.2%
250 - MGS - Primary - Summer	75,000	300	200	8,594.73	8,858.68	263.95	3.1%
250 - MGS - Primary - Summer	125,000	500	300	13,760.96	14,190.01	429.05	3.1%
250 - MGS - Primary - Summer	175,000	700	450	19,687.57	20,293.02	605.45	3.1%
250 - MGS - Primary - Winter	35,000	150	100	4,365.95	4,500.10	134.15	3.1%
250 - MGS - Primary - Winter	75,000	300	200	8,965.35	9,229.30	263.95	2.9%
250 - MGS - Primary - Winter	125,000	500	300	14,378.67	14,807.72	429.05	3.0%
250 - MGS - Primary - Winter	175,000	700	450	20,552.36	21,157.81	605.45	2.9%
251 - MGS Electric Heat - Secondary - Winter	35,000	150	100	4,162.19	4,210.84	48.65	1.2%
251 - MGS Electric Heat - Secondary - Winter	75,000	300	200	8,472.63	8,565.58	92.95	1.1%
251 - MGS Electric Heat - Secondary - Winter	125,000	500	300	13,455.06	13,599.11	144.05	1.1%
251 - MGS Electric Heat - Secondary - Winter	175,000	700	450	19,351.47	19,557.92	206.45	1.1%
251 - MGS Electric Heat - Primary - Winter	35,000	150	100	4,076.69	4,125.34	48.65	1.2%
251 - MGS Electric Heat - Primary - Winter	75,000	300	200	8,301.63	8,394.58	92.95	1.1%
251 - MGS Electric Heat - Primary - Winter	125,000	500	300	13,170.06	13,314.11	144.05	1.1%
251 - MGS Electric Heat - Primary - Winter	175,000	700	450	18,952.47	19,158.92	206.45	1.1%

Table 5-15: Large General Service Bill Comparison

RATE CLASS	ENERGY	FACILITY	BILLED DEMAND	EXISTING BILL(1)	RECOMMENDED		
					BILL(1)	INCREASE	INCREASE
	kWh	kW	kW	$	$	$	%
Monthly							
300 - LGS - Secondary - Summer	480,000	1,500	1,000	54,199.12	54,495.32	296.20	0.5%
300 - LGS - Secondary - Summer	680,000	2,000	1,500	77,749.18	78,152.38	403.20	0.5%
300 - LGS - Secondary - Summer	920,000	2,500	2,000	103,731.24	104,245.04	513.80	0.5%
300 - LGS - Secondary - Winter	480,000	1,500	1,000	52,678.31	52,974.51	296.20	0.6%
300 - LGS - Secondary - Winter	680,000	2,000	1,500	75,594.70	75,997.90	403.20	0.5%
300 - LGS - Secondary - Winter	920,000	2,500	2,000	100,816.36	101,330.16	513.80	0.5%
300 - LGS - Primary - Summer	920,000	2,750	2,000	95,735.04	96,253.84	518.80	0.5%
300 - LGS - Primary - Summer	1,400,000	4,000	3,000	144,126.36	144,886.36	760.00	0.5%
300 - LGS - Primary - Summer	1,840,000	5,500	4,000	191,300.08	192,327.68	1,027.60	0.5%
300 - LGS - Primary - Winter	920,000	2,750	2,000	100,281.36	100,800.16	518.80	0.5%
300 - LGS - Primary - Winter	1,400,000	4,000	3,000	151,044.67	151,804.67	760.00	0.5%
300 - LGS - Primary - Winter	1,840,000	5,500	4,000	200,392.72	201,420.32	1,027.60	0.5%
301 - LGS Electric Heat - Secondary - Winter	480,000	1,500	1,000	47,564.92	48,084.92	520.00	1.1%
301 - LGS Electric Heat - Secondary - Winter	680,000	2,000	1,500	68,607.48	69,349.98	742.50	1.1%
301 - LGS Electric Heat - Secondary - Winter	920,000	2,500	2,000	91,272.44	92,237.44	965.00	1.1%
301 - LGS Electric Heat - Primary - Winter	920,000	2,750	2,000	90,737.44	91,707.44	970.00	1.1%
301 - LGS Electric Heat - Primary - Winter	1,400,000	4,000	3,000	136,387.36	137,822.36	1,435.00	1.1%
301 - LGS Electric Heat - Primary - Winter	1,840,000	5,500	4,000	181,304.88	183,234.88	1,930.00	1.1%

Table 5-16: Large Power Service Bill Comparison

RATE CLASS	ENERGY	FACILITY	BILLED DEMAND	EXISTING BILL(1)	RECOMMENDED		
					BILL(1)	INCREASE	INCREASE
	kWh	kW	kW	$	$	$	%
Monthly							
400 - LPS - Secondary - Summer	1,280,000	3,500	2,500	115,131.40	116,175.80	1,044.40	0.9%
400 - LPS - Secondary - Summer	1,560,000	4,000	3,000	138,546.80	139,775.60	1,228.80	0.9%
400 - LPS - Secondary - Summer	1,800,000	4,750	3,500	160,897.00	162,336.00	1,439.00	0.9%
400 - LPS - Secondary - Winter	1,280,000	3,500	2,500	121,456.71	122,501.11	1,044.40	0.9%
400 - LPS - Secondary - Winter	1,560,000	4,000	3,000	146,255.78	147,484.58	1,228.80	0.8%
400 - LPS - Secondary - Winter	1,800,000	4,750	3,500	169,791.97	171,230.97	1,439.00	0.8%
400 - LPS - Primary - Summer	1,880,000	6,000	3,500	181,104.20	182,486.60	1,382.40	0.8%
400 - LPS - Primary - Summer	2,720,000	9,000	5,000	261,702.80	263,698.40	1,995.60	0.8%
400 - LPS - Primary - Summer	3,800,000	12,000	7,000	364,048.00	366,792.00	2,744.00	0.8%
400 - LPS - Primary - Winter	1,880,000	6,000	3,500	175,147.71	176,530.11	1,382.40	0.8%
400 - LPS - Primary - Winter	2,720,000	9,000	5,000	253,084.89	255,080.49	1,995.60	0.8%
400 - LPS - Primary - Winter	3,800,000	12,000	7,000	352,008.28	354,752.28	2,744.00	0.8%
400 - LPS - Substation - Summer	6,750,000	15,000	12,000	592,748.50	596,443.50	3,695.00	0.6%
400 - LPS - Substation - Summer	9,050,000	20,000	16,000	792,997.50	797,916.50	4,919.00	0.6%
400 - LPS - Substation - Summer	11,300,000	25,000	20,000	990,447.00	996,591.00	6,144.00	0.6%
400 - LPS - Substation - Winter	6,750,000	15,000	12,000	571,362.15	575,057.15	3,695.00	0.6%
400 - LPS - Substation - Winter	9,050,000	20,000	16,000	764,323.95	769,242.95	4,919.00	0.6%
400 - LPS - Substation - Winter	11,300,000	25,000	20,000	954,644.67	960,788.67	6,144.00	0.6%
401 - LPS Electric Heat - Primary - Winter	1,880,000	6,000	3,500	158,011.40	157,609.30	(402.10)	-0.3%
401 - LPS Electric Heat - Primary - Winter	2,720,000	9,000	5,000	228,191.60	227,564.20	(627.40)	-0.3%
401 - LPS Electric Heat - Primary - Winter	3,800,000	12,000	7,000	317,254.00	316,343.00	(911.00)	-0.3%
401 - LPS Electric Heat - Secondary - Winter	1,280,000	3,500	2,500	109,973.40	109,878.30	(95.10)	-0.1%
401 - LPS Electric Heat - Secondary - Winter	1,560,000	4,000	3,000	132,186.80	131,996.60	(190.20)	-0.1%
401 - LPS Electric Heat - Secondary - Winter	1,800,000	4,750	3,500	153,619.00	153,445.50	(173.50)	-0.1%

APPENDIX A – ONE PAGE SUMMARY

BPU 2023 Electric Rate Study

SUMMARY

KANSAS CITY BPU THE POWER OF COMMUNITY

Study Overview

The BPU engaged 1898 & Co., a division of Burns & McDonnell Engineering Company to conduct a comprehensive electric rate study consisting of an evaluation of revenue and revenue requirements over a five-year period, an allocated cost of service study, and rate design.

Key Outcomes of Electric Study

FINANCIAL FORECAST

- 5-Year Financial Forecast indicates the need for two 2.50% base rate increases effective July 1, 2023 and July 1, 2024.
- The Electric Utility plans to issue a $50 million revenue bond to fund a portion of its 5-year Capital Improvement Plan (CIP), which has the effect of reducing the required rate increase while also increasing required cash reserves.
- The BPU has revised its policy on minimum cash reserves to require at least 120 days of operating expenses in unrestricted cash balances.
    - Two new reserve funds have been created to manage the minimum balance: an O&M Reserve and an ERC Reserve.
- The ERC Reserve will be funded gradually over five years to build up the required balance through the ERC charge.

COST OF SERVICE STUDY

- Cost of Service Study indicates the Residential Class is recovering less than its equitable share of costs and the commercial and industrial class are over-recovering their share of costs.
- To account for this and move the classes closer to equitable recovery of each classes cost to provide electric service, we proposed Residential receive a base rate increase above the system average (3.75%) and the commercial and industrial classes receive below the system average (1.75%).

RATE DESIGN

Proposed changes in Rate Design are listed below:

- Merging of the standard Residential and Residential Electric Heat classes into one Residential class that is modeled like the existing electric heating rate design.
- Slightly larger increase in fixed cost portion of rates (customer and demand charges) as opposed to energy rates to reflect cost causation and recovery of more fixed costs through fixed charges.
- Creation of a Green Rider that allows customers to purchase energy with environmental attributes to meet renewable energy goals.
- Modifying the ERC Rider to allow for additional recovery to build and maintain the new ERC reserve fund.

Key Drivers for Base Rate Increase

- Inflationary increases in operating expenses and materials costs.
- Transfer of $2.0 million that is currently recovered in the ERC to base rates.
- Building to a minimum of 120 days of cash operating reserves.
- Additional debt service for a $50 million revenue bond.

APPENDIX B – PROPOSED RATE MANUAL

RATE APPLICATION MANUAL

Kansas City
Board of Public Utilities

KCBPU BASE RATES APPROVED BY THE BPU BOARD July 1, 2023
UG/WYCO RATES APPROVED BY THE UG BOARD of COMMISIONERS September 15, 2022
EFFECTIVE July 1, 2023

RATE APPLICATION MANUAL		
INTRODUCTION	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 1

This manual has been prepared to assist in the application of rates of the Board of Public Utilities (BPU) of Kansas City, Kansas and in the billing of rates of the Unified Government of Wyandotte County/Kansas City, Kansas (the Unified Government). It is divided into six sections, with Section I being an introduction and a glossary containing definitions of terms used in Section II and III of this manual.

Sections II and III include all the electric and water rate schedules for the BPU under which customers may be served. Sections IV, V and VI include rate schedules for water pollution, residential trash service and storm water fees of the Unified Government. These rates are set by the Unified Government, and these services are provided by the Unified Government and are billed by the BPU. The inclusion of the rates set forth in Section IV, V and VI of the rate manual are for billing reference purposes only.

In the event that a customer qualifies for service under more than one BPU rate schedule, the customer should be placed on the rate which is most favorable to the customer. However, this does not mean that the customer should be switched from one schedule to another during different periods of the year. While the rates contained herein are based upon monthly use, they have been determined on an annual basis, which means that once a rate schedule is selected it should remain in effect for that customer for at least one year.

RATE APPLICATION MANUAL		
DEFINITIONS	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 5

The following is a list of definitions of terms used in this manual. It is provided for the purpose of assisting the users in proper use and application of the rates. These definitions and terms are those commonly used in the utility industry. Should you have any questions or need further clarification, please contact the Customer Service Department.

BASE MONTHLY CHARGES: Base Monthly Charges are defined as the amount determined from the application of the rate schedule before adding (or subtracting) any amount from the application of any Rider or the addition of any tax.

BILLING CYCLE: The regular periodic interval used for reading a customer's meter for billing purposes. The normal billing cycle is between 24 and 36 days.

BOARD OF PUBLIC UTILITIES (BPU): An administrative agency of the Unified Government that provides retail and wholesale Electric and Water service to Kansas City, Kansas and local jurisdictions.

COMMERCIAL USE: A customer using electric and water service in the conduct of an enterprise or activity in space occupied and operated for commercial or institutional purposes. Commercial use is defined as non-residential consumption.

CONTRACT DEMAND: A customer's contract demand is the amount of power which a customer agrees to pay to have available at all times. Because this refers to power, which must be made available, as opposed to energy, which can actually be consumed, contract demand is measured in kilowatts, not kilowatt-hours.

CUBIC FOOT (CU. FT.): A cubic foot is a volumetric measurement of use in the water industry and contains approximately 7.48 gallons. One hundred (100) cubic feet (CCF) is therefore approximately 748 gallons.

CUSTOMER: An individual, firm or organization that purchases service at one location through a single meter under one rate classification, contract or schedule. If service is supplied at more than one location or under more than one rate schedule, each location, meter or rate schedule shall receive a separate Customer Charge for billing purposes.

CUSTOMER CHARGE: A Customer Charge is one of the Base Monthly Charges in a rate schedule. This charge normally provides for recovery of costs incurred in providing service to customers and is not related to how much energy a customer uses. The Customer Charge represents a portion of the cost of system access and customer service including the cost of meter reading, bill calculation, postage and the expenses associated with the basic plant investment at each service location, such as meters, transformers, service lines, etc.

DEMAND: The greatest average customer load on the Utility's electric system measured in a 30-minute period during the Billing Cycle, expressed in terms of kilowatts.

DEMAND CHARGE: A Demand Charge is a rate applied to a customer's billing demand expressed in Kilowatts (kW). Such a charge is commonly used for General Service and Large Power Service customers.

DISTRIBUTION: The locally-owned power system used to deliver electric energy to Utility's native load customers. Distribution facilities are lower-voltage when compared to transmission high voltage facilities.

ENERGY CHARGE: An Energy Charge is a rate applied to the amount of energy used by a customer, expressed in Kilowatt-hours (kWh).

ENERGY RATE COMPONENT: The Energy Rate Component (ERC) is a rider applied to the amount of energy used by a customer to recover the Utility's fuel and all purchased power costs and other ancillary costs incurred to provide energy to customers.

ENVIRONMENTAL SURCHARGE: The Environmental Surcharge (ESC) is a rider to provide for the annual recovery of the Utility's capital investment in projects that are required to meet Federal, State or Local environmental regulations.

FACILITIES CHARGE: A monthly charge used to recover capital costs and related expenses associated with distributing electricity from the Utility's substation to the customer's service conductor (or for primary service to the customer's transformer.) The Facilities Charge is based on the customer's Demand.

FACILITIES DEMAND: The Facilities Demand shall be equal to the highest metered Demand occurring in the current month or the preceding eleven (11) months. In no event shall the Facilities Demand be less than the customer's contract demand.

FUEL: Any material substance that can be consumed to supply heat or power. Included are petroleum, coal, and natural gas (the fossil fuels), and other consumable materials, such as uranium, biomass, and hydrogen.

FULL REQUIREMENTS CUSTOMER: A customer without other generating resources behind the meter with BPU as the sole source of long-term firm power.

HOLIDAYS: The following days:

1 New Year's Day
2 Martin Luther King's Day
3 President's Day
4 Memorial Day
5 Independence Day
6 Labor Day
7 Thanksgiving Day
8 Day After Thanksgiving
9 Christmas Day

If the holiday falls on a Saturday, the previous Friday is off-peak. If the holiday falls on a Sunday, the following Monday is off-peak. Provided, however, that if the applicable holiday, if any, is celebrated on a day other than the previous Friday or following Monday, as applicable, then the off-peak savings day will be the day that the applicable holiday is celebrated.

INDUSTRIAL USE: A customer using energy or water in the production, processing, or assembling of goods. Industrial use is defined as non-residential use.

KILOVOLT-AMPERE (kVa): A unit of apparent power, equal to 1,000 volt-amperes; the mathematical product of the volts and amperes in an electrical circuit.

KILOWATT (kW): A Kilowatt is 1000 watts (Kilo = 1000, and a watt is a measurement of electrical power).

KILOWATT-HOUR (kWh): A kilowatt-hour is 1000 watt-hours and is a measure of energy. It is the time rate use of power. As an example: A 100 watt light bulb used for 10 hours would be 1000 watt-hours or 1 kWh.

LOAD: The amount of electric power required at any specified point or points on the electric system. Load originates primarily at the power consuming equipment of the customers.

LOAD FACTOR: A measurement showing how efficiently capacity is being utilized within a system. The higher the load factor, the better the efficiency. Load factor is the ratio of the average load in kilowatts supplied during a designated period to the peak load in kilowatts occurring in that period. Load factor, expressed as a percentage, is calculated by multiplying the kilowatt-hours in the period by 100 and dividing by the product of the maximum demand in kilowatts and the number of hours in the period.

OFF-PEAK: The Board of Public Utilities off-peak hours are all hours of the year not designated as on-peak hours.

ON-PEAK: The Board of Public Utilities on-peak hours are designated as being from 10:01 a.m. to 8:00 p.m. each Monday through Friday, excluding holidays.

PARTIAL REQUIREMENTS CUSTOMER: A customer with generating resources connected to its electrical load that is either insufficient to carry all its load or that voluntarily uses self-generating resources to offset BPU service while remaining connected to the BPU system and requiring standby service. Emergency-only backup generation is excluded if used exclusively either for testing purposes or when service from the BPU is not available due to a power outage or forced curtailment. The emergency generation is not connected electrically to the BPU system and cannot flow back into that system.

PAYMENT IN LIEU OF TAXES (PILOT): A fee set by Unified Government (UG) ordinance that requires the BPU to pay a percentage of its gross revenues to meet certain UG costs incurred due to BPU operating as a public utility. The PILOT is in lieu of property taxes and franchise fees.

PEAK DEMAND: The maximum 30-minute delivery of power to the customer during the defined period; measured in kW.

POWER FACTOR: Power Factor is a term used to express the ratio of actual power required by a customer's load versus the amount of power that has to be generated to serve that load. Certain appliances, such as motors, require that more power be supplied to operate the device than just the amount of power the device puts out.

PRIMARY SERVICE: Single or three phase service taken from the Board's system at a standard available voltage greater than 480 volts provided there is only one transformation involved from the Board's transmission voltage to the service voltage.

PURCHASED POWER: Power purchased or available for purchase from a source outside the system.

REACTIVE POWER: The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is a derived value equal to the vector difference between the apparent power and the real power. It is usually expressed as kilovolt-amperes reactive (KVAR) or megavolt-ampere reactive (MVAR).

RENEWABLE ENERGY: Energy resources that are naturally replenishing but flow-limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Renewable energy resources include biomass, hydro, geothermal, solar, wind, ocean thermal, wave action, and tidal action.

RESIDENTIAL USE: A consumer using electric and water service for general household purposes in space occupied as living quarters, such as single private residences, single flats, apartment units, multi-family dwellings, or single mobile homes.

RIDER: A Rider is an addition to the rate schedule. The primary purpose of a rider is to set out a provision that may not be included in the Base Monthly Charges and may have application to more than one rate schedule and thus eliminates the need for redundancy from one rate schedule to another.

SECONDARY SERVICE: Single or three phase service taken from the Board's system at a standard available voltage at or below 480 volts provided the conditions defined under "Primary Service" are not applicable.

SUBSTATION: A facility, which changes or regulates the voltage of electricity from transmission to distribution.

SUMMER: Summer is defined as the four months billed in June through September. For cycle billed customers, the summer is defined as the four consecutive cycles billed on or after June 1.

TERM OF CONTRACT: The minimum term of contract applicable to non-residential rate schedules shall be twelve (12) months.

TRANSFORMER: An electromagnetic device for changing the voltage of alternating current electricity.

TRANSMISSION: The process of transporting electric energy in bulk from a source of supply to other principal parts of the system or to other utilities. Transmission refers to the high-voltage facilities, which transport electric energy.

TRANSMISSION SERVICE: Service available for Non-Residential customers that has connected load directly to BPU owned transmission lines greater than 69,000-volt.

UNIFIED GOVERNMENT: Kansas City, Kansas is a city in the state of Kansas and is the county seat of Wyandotte County. It is part of a consolidated city-county government known as the "Unified Government"(UG).

WATER PLAN FEE: A state fee, required of all water customers in Kansas. State law requires all water utilities to collect a consumption-based fee from customers and remit it to the State of Kansas for the Kansas Water Plan. The state uses this money to manage statewide water issues like sustainable sources, flood management, water quality, and wetland protection.

WINTER: The period defined as the eight consecutive non-Summer billing periods.

ELECTRIC RATE SCHEDULE		
GENERAL PURPOSE RESIDENTIAL RATE RATE CODE 100	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 1

AVAILABILITY:
At any point on the Board's existing secondary distribution system.

APPLICATION:
For all residential service to single family residences or individually metered residential dwellings.

CHARACTER OF SERVICE:
Service will normally be single-phase, 60 cycles at approximately 120/240 volts. Three-phase service may be made available as provided for by the Board's Rules and Regulations.

MONTHLY RATE for Rate Code 100:

CUSTOMER CHARGE:	$	24.00	per Billing Cycle		
ENERGY CHARGE:		**SUMMER**		**WINTER**	
First 1,000 kWh:	$	0.06911	$	0.06650	per kWh
All Additional kWh	$	0.06911	$	0.03750	per kWh

MINIMUM BILL:
The Monthly Customer Charge.

APPLICABLE RIDERS:

El	Energy Rate Component Rider
E2	Payment-In-Lieu-Of-Tax
E16	Electric Rate Stabilization Rider
E17	Environmental Surcharge Rider

RATE CODE:	**100**
EFFECTIVE:	**7/1/2023**
SUPERSEDES RATE EFFECTIVE:	**1/1/2018**

ELECTRIC RATE SCHEDULE		
SMALL GENERAL SERVICE RATE RATE CODE 200-222	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 3

AVAILABILITY:
At any point on the Board's existing distribution system having adequate capacity and suitable voltage for service.

APPLICATION:
For all non-residential service for which no specific schedule is otherwise provided. For service to customers with a metered demand less than 70 kW.

CHARACTER OF SERVICE:
Service will be either single-phase or three-phase, 60 cycles at a standard voltage as available at customer's service location. Service requested by customer at other voltages will be provided in accordance with the Board's Rules and Regulations.

MONTHLY RATE for Rate Code 200-222:

CUSTOMER CHARGE:	$	42.00	per Billing Cycle
a) For Customers with Demand Meter:			
FACILITIES CHARGE:			
Secondary Service	$	3.38	per kW
Primary Service	$	2.74	per kW
DEMAND CHARGE:			
First 10 kW	NO CHARGE		
All Additional kW	$	5.75	per kW
ENERGY CHARGE:			
All kWh	$	0.04746	per kWh
b) For Customers without Demand Meter:			
ENERGY CHARGE:			
All kWh	$	0.08850	per kWh

MINIMUM BILL:
The Monthly Customer Charge plus the Facilities Charge plus any Demand Charge.

ELECTRIC RATE SCHEDULE		
SMALL GENERAL SERVICE RATE RATE CODE 200-222	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 2 OF 3

DEMAND METERING REQUIREMENT: In the event that a customer uses more than 3,600 kWh for any four consecutive billing periods, a demand meter may be installed and the customer billed under the portion of the schedule applicable to demand metered customers. If the measured demand is below 10 kW for 12 consecutive months, the customer may return to the portion of the schedule for customers without a demand meter. In the event that a customer's measured demand is 70 kW or greater in any two of the preceding 11 months or the current month the customer shall be moved from the Small General Service Rate to the applicable rate based on billing demand.

FACILITIES DEMAND:
The Facilities Demand shall be equal to the highest metered 30-minute Demand occurring in the current month or the preceding eleven (11) months. In no event shall the Facilities Demand be less than the customer's contract demand.

BILLING DEMAND:
The billing demand for the summer months June through September shall be the greatest average metered kilowatt demand measured in any 30-minute period during the month. The billing demand during the winter period shall be the greater of the largest billing demand during the current month or 70% of the largest billing demand during the aforementioned Summer months.

TIME–OF-USE-OPTION:
This option is available only to existing customers identified by BPU which were exercising this option as of December 31, 2016; this option is not available to any other customers. Where time-of-use metering equipment has been installed at such an identified customer's expense, the summer period billing demand shall be the greatest average kilowatt demand measured in any 30-minute period between the hours of 10:01 a.m. and 8:00 p.m., excluding weekends and Holidays. This time of use option applies only to billing demand, not to Facilities Demand. Facilities Demand charges will apply as provided under the caption “Facilities Demand.”

METERING OPTION:
At the Utility's option, suitable metering equipment may be installed on the primary side of the transformer.

PRIMARY METERING ADJUSTMENT:
The monthly Facilities, Demand and Energy Charges are based on secondary metering. When a primary meter is installed, the customer's measured kWh and kW shall be decreased by 2.0%.

TRANSFORMER RENTAL:
Customers may, upon the approval of the Board, rent their service transformers and related equipment for a monthly fee equivalent to the cost of providing and maintaining these facilities. Any customer receiving a Primary Metering Adjustment will be required to own or rent its service transformers and related equipment behind the primary metering point.

ELECTRIC RATE SCHEDULE		
SMALL GENERAL SERVICE RATE RATE CODE 200-222	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 3 OF 3

TERM OF CONTRACT:
12 months for service under any provisions of this schedule.

APPLICABLE RIDERS:

El	Energy Rate Component Rider
E2	Payment-In-Lieu-Of-Tax
E7	Reactive Adjustment
E16	Electric Rate Stabilization Rider
E17	Environmental Surcharge Rider

RATE CODE:	**200**
EFFECTIVE:	**7/1/2023**
SUPERSEDES RATE EFFECTIVE:	**1/1/2018**

ELECTRIC RATE SCHEDULE		
SMALL GENERAL SERVICE ELECTRIC HEATING RATE RATE CODE 201-223	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 3

AVAILABILITY:
At any point on the Board's existing distribution system having adequate capacity and suitable voltage for service.

APPLICATION:
For commercial service to customers with a metered demand less than 70 kW using electric heat as the primary source of space heating, termed commercial heating customers, as further described below:

1. Available to customers with permanently installed electric space heating equipment. The electric heating equipment shall be of a design approved by the Board of Public Utilities, and shall be thermostatically controlled, in regular use, and the primary source of space heating (exclusive of aesthetic fireplaces).

2. The customer's meter must achieve a Peak Winter Period Demand of at least 90% of the previous Peak Summer Demand at least once every three years. The Average monthly Peak Winter Demand must also be at least 80% of the Average monthly Peak Summer Demand at least once every three years. If either of these criteria are not met the customer will be moved to the corresponding standard customer class for a period of at least twelve months at which time the customer can re-apply if all conditions of the customer class can be shown as to being achieved during that time.

3. Customer must apply for this rate, and the installation must pass the Board of Public Utilities size and efficiency tests. Use of such commercial electric heating equipment is subject to rules and regulations, and approval by the local authority having jurisdiction.

CHARACTER OF SERVICE:
Service will be either single-phase or three-phase, 60 cycles at a standard voltage as available at customer's service location. Service requested by customer at other voltages will be provided in accordance with the Board's Rules and Regulations.

ELECTRIC RATE SCHEDULE		
SMALL GENERAL SERVICE ELECTRIC HEATING RATE RATE CODE 201-223	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 2 OF 3

MONTHLY RATE for Rate Code 201-223:

CUSTOMER ACCESS CHARGE:	$ 42.00	per Billing Cycle		
FACILITIES CHARGE:				
Secondary Service	$ 3.38	per kW		
Primary Service	$ 2.74	per kW		
DEMAND CHARGE:				
First 10 kW	NO CHARGE			
All Additional kW	$ 5.75	per kW		
ENERGY CHARGE:	**SUMMER**	**WINTER**		
First 3,500 kWh	$ 0.04746	$ 0.04746	per kWh	
All Additional kWh	$ 0.04746	$ 0.02712	per kWh	

MINIMUM BILL:
The Monthly Customer Charge plus the Facilities Charge plus any Demand Charge.

FACILITIES DEMAND:
The Facilities Demand shall be equal to the highest metered 30-minute Demand occurring in the current month or the preceding eleven (11) months. In no event shall the Facilities Demand be less than the customer's contract demand.

BILLING DEMAND:
The billing demand for the summer months June through September shall be the greatest average metered kilowatt demand measured in any 30-minute period during the month. The billing demand during the winter period shall be the lesser of the largest billing demand during the current month or 70% of the largest billing demand during the aforementioned Summer months.

ELECTRIC RATE SCHEDULE		
SMALL GENERAL SERVICE ELECTRIC HEATING RATE RATE CODE 201-223	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 3 OF 3

METERING OPTION:
At the Utility's option, suitable metering equipment may be installed on the primary side of the transformer.

PRIMARY METERING ADJUSTMENT:
The monthly Facilities, Demand and Energy Charges are based on secondary metering. When a primary meter is installed, the customer's measured kWh and kW shall be decreased by 2.0%.

TRANSFORMER RENTAL:
Customers may, upon the approval of the Board, rent their service transformers and related equipment for a monthly fee equivalent to the cost of providing and maintaining these facilities. Any customer receiving a Primary Metering Adjustment will be required to own or rent its service transformers and related equipment behind the primary metering point.

TERM OF CONTRACT:
12 months for service under any provisions of this schedule.

APPLICABLE RIDERS:

El	Energy Rate Component Rider
E2	Payment-In-Lieu-Of-Tax
E7	Reactive Adjustment
E16	Electric Rate Stabilization Rider
E17	Environmental Surcharge Rider

RATE CODE:	**201**
EFFECTIVE:	**7/1/2023**
SUPERSEDES RATE EFFECTIVE:	**1/1/2018**

ELECTRIC RATE SCHEDULE		
MEDIUM GENERAL SERVICE RATE RATE CODE 250-262	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 2

AVAILABILITY:
At any point on the Board's existing distribution system having adequate capacity and suitable voltage for service.

APPLICATION:
For service to customers with a metered demand of 70 kW to 1000 kW.

CHARACTER OF SERVICE:
Service will be either single-phase or three-phase, 60 cycles at a standard delivery voltage as available at customer's service location. Service requested by customer at other voltages will be provided in accordance with the Board's Rules and Regulations.

MONTHLY RATE for Rate Code 250-262:

CUSTOMER ACCESS CHARGE:	$	90.00	per Billing Cycle
FACILITIES CHARGE:			
Secondary Service	$	4.22	per kW
Primary Service	$	3.65	per kW
DEMAND CHARGE:			
All kW	$	6.88	per kW
ENERGY CHARGE:			
First 300 kWh per kW	$	0.03739	per kWh
All Additional kWh	$	0.02201	per kWh

MINIMUM BILL:
The Monthly Customer Charge plus the Facilities Charge plus any Demand Charge.

FACILITIES DEMAND:
The Facilities Demand shall be equal to the greater of the contract demand or the highest metered 30-minute Demand occurring in the current month or the preceding eleven (11) months. In no event shall the Facilities Demand be less than 70 kW or the customer's contract demand.

BILLING DEMAND:
The billing demand during the summer months of June through September shall be the larger of the contract demand (as mutually agreed upon) or the greatest average kilowatt demand measured in any 30-minute period during the month but not less than 70 kW. The billing demand during the winter period shall be the greater of the largest billing demand during the current month or 70% of the largest billing demand during the aforementioned Summer months.

ELECTRIC RATE SCHEDULE		
MEDIUM GENERAL SERVICE RATE RATE CODE 250-262	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 2 OF 2

TIME–OF-USE- OPTION:
This option is available only to existing customers identified by BPU which were exercising this option as of December 31, 2016; this option is not available to any other customers. Where time-of-use metering equipment has been installed at such an identified customer's expense, the summer period billing demand shall be the greatest average kilowatt demand measured in any 30-minute period between the hours of 10:01 a.m. and 8:00 p.m., excluding weekends and Holidays. This time of use option applies only to billing demand, not to Facilities Demand. Facilities Demand charges will apply as provided under the caption "Facilities Demand."

METERING OPTION:
At the Utility's option, suitable metering equipment may be installed on the secondary side of the transformer.

SECONDARY METERING ADJUSTMENT:
The monthly Facilities, Demand and Energy Charges are based on primary metering. When a secondary meter is installed which does not compensate for transformer losses, the customer's metered kWh and kW shall be increased by 2.0%.

TRANSFORMER RENTAL:
Customers may, upon the approval of the Board, rent their service transformers and related equipment for a monthly fee equivalent to the cost of providing and maintaining these facilities. Any customer receiving a Primary Metering Adjustment will be required to own or rent its service transformers and related equipment behind the primary metering point.

APPLICABLE RIDERS:

El	Energy Rate Component Rider
E2	Payment-In-Lieu-Of-Tax
E7	Reactive Adjustment
E16	Electric Rate Stabilization Rider
E17	Environmental Surcharge Rider

RATE CODE:	**250**
EFFECTIVE:	**7/1/2023**
SUPERSEDES RATE EFFECTIVE:	**1/1/2018**

ELECTRIC RATE SCHEDULE		
MEDIUM GENERAL SERVICE ELECTRIC HEATING RATE RATE CODE 251-263	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 3

AVAILABILITY:
At any point on the Board's existing distribution system having adequate capacity and suitable voltage for service.

APPLICATION:
For service to commercial use customers with a metered demand of 70 kW to 1000 kW using electric heat as the primary source of space heating, termed commercial heating customers, as further described below:

1. Available to customers with permanently installed electric space heating equipment. The electric heating equipment shall be of a design approved by the Board of Public Utilities, and shall be thermostatically controlled, in regular use, and the primary source of space heating (exclusive of aesthetic fireplaces).

2. The customer's meter must achieve a Peak Winter Period Demand of at least 90% of the previous Peak Summer Demand at least once every three years. The Average monthly Peak Winter Demand must also be at least 80% of the Average monthly Peak Summer Demand at least once every three years. If either of these criteria are not met the customer will be moved to the corresponding standard customer class for a period of at least twelve months at which time the customer can re-apply if all conditions of the customer class can be shown as to being achieved during that time.

3. Customer must apply for this rate, and the installation must pass the Board of Public Utilities size and efficiency tests. Use of such commercial electric heating equipment is subject to rules and regulations, and approval by the local authority having jurisdiction.

CHARACTER OF SERVICE:
Service will be either single-phase or three-phase, 60 cycles at a standard delivery voltage as available at customer's service location. Service requested by customer at other voltages will be provided in accordance with the Board's Rules and Regulations.

ELECTRIC RATE SCHEDULE		
MEDIUM GENERAL SERVICE ELECTRIC HEATING RATE RATE CODE 251-263	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 2 OF 3

MONTHLY RATE for Rate Code 251-263:

CUSTOMER ACCESS CHARGE:	$	90.00	per Billing Cycle		
FACILITIES CHARGE:					
Secondary Service	$	4.22	per kW		
Primary Service	$	3.65	per kW		
DEMAND CHARGE:					
All kW	$	6.88	per kW		
ENERGY CHARGE:		**SUMMER**		**WINTER**	
First 300 kWh per kW	$	0.03739	$	0.03739	per kWh
All Additional kWh	$	0.02201	$	0.01177	per kWh

MINIMUM BILL:
The Monthly Customer Charge plus the Facilities Charge plus any Demand Charge.

FACILITIES DEMAND:
The Facilities Demand shall be equal to the greater of the contract demand or the highest metered 30-minute Demand occurring in the current month or the preceding eleven (11) months. In no event shall the Facilities Demand be less than 70 kW or the customer's contract demand.

BILLING DEMAND:
The billing demand during the summer months of June through September shall be the larger of the contract demand (as mutually agreed upon) or the greatest average kilowatt demand measured in any 30-minute period during the month but not less than 70 kW. The billing demand during the winter period shall be the lesser of the largest billing demand during the current month or 70% of the largest billing demand during the aforementioned Summer months.

ELECTRIC RATE SCHEDULE		
MEDIUM GENERAL SERVICE ELECTRIC HEATING RATE RATE CODE 251-263	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 3 OF 3

METERING OPTION:
At the Utility's option, suitable metering equipment may be installed on the secondary side of the transformer.

SECONDARY METERING ADJUSTMENT:
The monthly Facilities, Demand and Energy Charges are based on primary metering. When a secondary meter is installed which does not compensate for transformer losses, the customer's metered kWh and kW shall be increased by 2.0%.

TRANSFORMER RENTAL:
Customers may, upon the approval of the Board, rent their service transformers and related equipment for a monthly fee equivalent to the cost of providing and maintaining these facilities. Any customer receiving a Primary Metering Adjustment will be required to own or rent its service transformers and related equipment behind the primary metering point.

APPLICABLE RIDERS:

El	Energy Rate Component Rider
E2	Payment-In-Lieu-Of-Tax
E7	Reactive Adjustment
E16	Electric Rate Stabilization Rider
E17	Environmental Surcharge Rider

RATE CODE:	**251**
EFFECTIVE:	**7/1/2023**
SUPERSEDES RATE EFFECTIVE:	**1/1/2018**

ELECTRIC RATE SCHEDULE		
LARGE GENERAL SERVICE RATE RATE CODE 300-322	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 2

AVAILABILITY:
At any point on the Board's existing distribution system having adequate capacity and suitable voltage for service.

APPLICATION:
For service to customers with metered demand of 1001 kW to 4000 kW.

CHARACTER OF SERVICE:
Service will be three-phase, 60 cycles at a standard delivery voltage as available at customer's service location. Service requested by customer at other voltages will be provided in accordance with the Board's Rules and Regulations.

MONTHLY RATE for Rate Code 300-322:

CUSTOMER ACCESS CHARGE:	$	180.00	per Billing Cycle
FACILITIES CHARGE:			
Secondary Service	$	4.26	per kW
Primary Service	$	3.68	per kW
DEMAND CHARGE:			
All kW	$	8.90	per kW
ENERGY CHARGE:			
First 300 kWh per kW	$	0.03661	per kWh
All Additional kWh	$	0.01591	per kWh

MINIMUM BILL:
The Monthly Customer Charge plus the Facilities Charge plus any Demand Charge.

FACILITIES DEMAND:
The Facilities Demand shall be equal to the greater of the contract demand or the highest metered 30-minute Demand occurring in the current month or the preceding eleven (11) months. In no event shall the Facilities Demand be less than 1001 kW or the customer's contract demand.

BILLING DEMAND:
The billing demand during the summer months of June through September shall be the larger of the contract demand (as mutually agreed upon) or the greatest average kilowatt demand measured in any 30-minute period during the month but not less than 1001 kW. The billing demand during the winter period shall be the greater of the largest billing demand during the current month or 70% of the largest billing demand during the aforementioned Summer months.

ELECTRIC RATE SCHEDULE		
LARGE GENERAL SERVICE RATE RATE CODE 300-322	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 2 OF 2

TIME–OF-USE- OPTION:
This option is available only to existing customers identified by BPU which were exercising this option as of December 31, 2016; this option is not available to any other customers. Where time-of-use metering equipment has been installed at such an identified customer's expense, the summer period billing demand shall be the greatest average kilowatt demand measured in any 30-minute period between the hours of 10:01 a.m. and 8:00 p.m., excluding weekends and Holidays. This time of use option applies only to billing demand, not to Facilities Demand. Facilities Demand charges will apply as provided under the caption "Facilities Demand."

METERING OPTION:
At the Utility's option, suitable metering equipment may be installed on the secondary side of the transformer.

SECONDARY METERING ADJUSTMENT:
The Monthly Facilities, Demand and Energy Charges are based on primary metering. When a secondary meter is installed which does not compensate for transformer losses, the customer's metered kWh and kW shall be increased by 2.0%.

TRANSFORMER RENTAL:
Customers may, upon the approval of the Board, rent their service transformers and related equipment for a monthly fee equivalent to the cost of providing and maintaining these facilities. Any customer receiving a Primary Metering Adjustment will be required to own or rent its service transformers and related equipment behind the primary metering point.

APPLICABLE RIDERS:

El	Energy Rate Component Rider
E2	Payment-In-Lieu-Of-Tax
E7	Reactive Adjustment
E16	Electric Rate Stabilization Rider
E17	Environmental Surcharge Rider

RATE CODE:	**300**
EFFECTIVE:	**7/1/2023**
SUPERSEDES RATE EFFECTIVE:	**1/1/2018**

ELECTRIC RATE SCHEDULE		
LARGE GENERAL SERVICE ELECTRIC HEATING RATE RATE CODE 301-323	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 3

AVAILABILITY:
At any point on the Board's existing distribution system having adequate capacity and suitable voltage for service.

APPLICATION:
For service to commercial customers with metered demand of 1001 kW to 4000 kW using electric heat as the primary source of space heating, termed commercial heating customers, as further described below:

1. Available to customers with permanently installed electric space heating equipment. The electric heating equipment shall be of a design approved by the Board of Public Utilities, and shall be thermostatically controlled, in regular use, and the primary source of space heating (exclusive of aesthetic fireplaces).

2. The customer's meter must achieve a Peak Winter Period Demand of at least 90% of the previous Peak Summer Demand at least once every three years. The Average monthly Peak Winter Demand must also be at least 80% of the Average monthly Peak Summer Demand at least once every three years. If either of these criteria are not met the customer will be moved to the corresponding standard customer class for a period of at least twelve months at which time the customer can re-apply if all conditions of the customer class can be shown as to being achieved during that time.

3. Customer must apply for this rate, and the installation must pass the Board of Public Utilities size and efficiency tests. Use of such commercial electric heating equipment is subject to rules and regulations, and approval by the local authority having jurisdiction.

CHARACTER OF SERVICE:
Service will be three-phase, 60 cycles at a standard delivery voltage as available at customer's service location. Service requested by customer at other voltages will be provided in accordance with the Board's Rules and Regulations.

ELECTRIC RATE SCHEDULE		
LARGE GENERAL SERVICE ELECTRIC HEATING RATE RATE CODE 301-323	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 2 OF 3

MONTHLY RATE for Rate Code 301-323:

CUSTOMER ACCESS CHARGE:	$	180.00	per Billing Cycle		
FACILITIES CHARGE:					
Secondary Service	$	4.26	per kW		
Primary Service	$	3.68	per kW		
DEMAND CHARGE:					
All kW	$	8.90	per kW		
ENERGY CHARGE:		**SUMMER**		**WINTER**	
First 300 kWh per kW	$	0.03661	$	0.03661	per kWh
All Additional kWh	$	0.01591	$	0.00555	per kWh

MINIMUM BILL:
The Monthly Customer Charge plus the Facilities Charge plus any Demand Charge.

FACILITIES DEMAND:
The Facilities Demand shall be equal to the greater of the contract demand or the highest metered 30-minute Demand occurring in the current month or the preceding eleven (11) months. In no event shall the Facilities Demand be less than 1001 kW or the customer's contract demand.

BILLING DEMAND:
The billing demand during the summer months of June through September shall be the larger of the contract demand (as mutually agreed upon) or the greatest average kilowatt demand measured in any 30-minute period during the month but not less than 1001 kW. The billing demand during the winter period shall be the lesser of the largest billing demand during the current month or 70% of the largest billing demand during the aforementioned Summer months.

METERING OPTION:
At the Utility's option, suitable metering equipment may be installed on the secondary side of the transformer.

SECONDARY METERING ADJUSTMENT:
The Monthly Facilities, Demand and Energy Charges are based on primary metering. When a secondary meter is installed which does not compensate for transformer losses, the customer's metered kWh and kW shall be increased by 2.0%.

ELECTRIC RATE SCHEDULE		
LARGE GENERAL SERVICE ELECTRIC HEATING RATE RATE CODE 301-323	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 3 OF 3

TRANSFORMER RENTAL:
Customers may, upon the approval of the Board, rent their service transformers and related equipment for a monthly fee equivalent to the cost of providing and maintaining these facilities. Any customer receiving a Primary Metering Adjustment will be required to own or rent its service transformers and related equipment behind the primary metering point.

APPLICABLE RIDERS:

El	Energy Rate Component Rider
E2	Payment-In-Lieu-Of-Tax
E7	Reactive Adjustment
E16	Electric Rate Stabilization Rider
E17	Environmental Surcharge Rider

RATE CODE:	**301**
EFFECTIVE:	**7/1/2023**
SUPERSEDES RATE EFFECTIVE:	**1/1/2018**

ELECTRIC RATE SCHEDULE		
LARGE POWER SERVICE RATE RATE CODE 400-446	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 3

AVAILABILITY:
At any point on the Board's existing system having adequate capacity and suitable voltage for secondary, primary or substation voltage level of service.

APPLICATION:
For service to customers having a demand of 4,001 kW or greater at least once in any given 12-month period or new loads estimated to reach at least 4,001 kW within two years. In the event that a customer has a demand of at least 4,001 kW and elects to be served under this rate, the rate shall be applied for a period of at least one year.

CHARACTER OF SERVICE:
Service will be at three-phase, 60 cycles at a standard delivery voltage as available at customer's service location. Service requested by customer at other voltages will be provided in accordance with the Board's Rules and Regulations.

MONTHLY RATE for Rate Code 400-446:

CUSTOMER ACCESS CHARGE:	$	420.00	per Billing Cycle
FACILITIES CHARGE:			
Secondary Service	$	3.50	per kW
Primary Service	$	2.95	per kW
Substation Service	$	1.03	per kW
DEMAND CHARGE:			
All kW	$	9.90	per kW
ENERGY CHARGE:			
First 300 kWh per kW	$	0.02211	per kWh
All Additional kWh	$	0.01099	per kWh

MINIMUM BILL:
The Monthly Customer Charge plus the Facilities Charge plus any Demand Charge.

FACILITIES DEMAND:
The Facilities Demand shall be equal to the greater of the contract demand or highest metered 30-minute Demand occurring in the current month or the preceding eleven (11) months. In no event shall the Facilities Demand be less than the customer's contract demand.

ELECTRIC RATE SCHEDULE		
LARGE POWER SERVICE RATE RATE CODE 400-446	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 2 OF 3

BILLING DEMAND:
The billing demand during the summer months of June through September shall be the larger of the contract demand (as mutually agreed upon) or the greatest average kilowatt demand measured in any 30-minute period during the month. The billing demand during the winter period shall be the greater of the largest billing demand during the current month or 70% of the largest billing demand during the aforementioned Summer months.

TIME–OF-USE- OPTION:
This option is available only to existing customers identified by BPU which were exercising this option as of December 31, 2016; this option is not available to any other customers. Where time-of-use metering equipment has been installed at such an identified customer's expense, the summer period billing demand shall be the greatest average kilowatt demand measured in any 30-minute period between the hours of 10:01 a.m. and 8:00 p.m., excluding weekends and Holidays. This time of use option applies only to billing demand, not to Facilities Demand. Facilities Demand charges will apply as provided under the caption "Facilities Demand."

METERING OPTION:
At the Utility's option, suitable metering equipment may be installed on the secondary side of the transformer.

METERING ADJUSTMENT:
The monthly demand and energy charges are based on primary metering. When a secondary, substation or transmission meter is installed which does not compensate for transformer losses, the customer's metered kWh's and kW will be adjusted as follows:

SECONDARY	Increased by 2.0%
PRIMARY	Increased by 0%
SUBSTATION	Decreased by 2.8%
TRANSMISSION	Decreased by 3.3%

TRANSFORMER RENTAL:
Customers may, upon the approval of the Board, rent their service transformers and related equipment for a monthly fee equivalent to the cost of providing and maintaining these facilities. Any customer receiving a Primary, Substation, or Transmission Metering Adjustment will be required to own or rent its service transformers and related equipment behind the metering point.

ELECTRIC RATE SCHEDULE		
LARGE POWER SERVICE RATE RATE CODE 400-446	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 3 OF 3

TERM OF CONTRACT:
12 months for service under any provisions of this schedule.

APPLICABLE RIDERS:

El	Energy Rate Component Rider
E2	Payment-In-Lieu-Of-Tax
E7	Reactive Adjustment
E16	Electric Rate Stabilization Rider
E17	Environmental Surcharge Rider

RATE CODE:	**400**
EFFECTIVE:	**7/1/2023**
SUPERSEDES RATE EFFECTIVE:	**1/1/2018**

ELECTRIC RATE SCHEDULE		
LARGE POWER SERVICE ELECTRIC HEATING RATE RATE CODE 401-447	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 3

AVAILABILITY:
At any point on the Board's existing system having adequate capacity and suitable voltage for secondary, primary or substation voltage level of service.

APPLICATION:
For service to commercial customers having a demand of 4,001 kW or greater at least once in any given 12-month period or new loads estimated to reach at least 4,001 kW within two years. In the event that a customer has a demand of at least 4,001 kW and elects to be served under this rate, the rate shall be applied for a period of at least one year. For service to commercial use customers using electric heat as the primary source of space heating, termed commercial heating customers, as further described below:

1. Available to customers with permanently installed electric space heating equipment. The electric heating equipment shall be of a design approved by the Board of Public Utilities, and shall be thermostatically controlled, in regular use, and the primary source of space heating (exclusive of aesthetic fireplaces).

2. The customer’s meter must achieve a Peak Winter Period Demand of at least 90% of the previous Peak Summer Demand at least once every three years. The Average monthly Peak Winter Demand must also be at least 80% of the Average monthly Peak Summer Demand at least once every three years. If either of these criteria are not met the customer will be moved to the corresponding standard customer class for a period of at least twelve months at which time the customer can re-apply if all conditions of the customer class can be shown as to being achieved during that time.

3. Customer must apply for this rate, and the installation must pass the Board of Public Utilities size and efficiency tests. Use of such commercial electric heating equipment is subject to rules and regulations, and approval by the local authority having jurisdiction.

CHARACTER OF SERVICE:
Service will be at three-phase, 60 cycles at a standard delivery voltage as available at customer's service location. Service requested by customer at other voltages will be provided in accordance with the Board's Rules and Regulations.

ELECTRIC RATE SCHEDULE		
LARGE POWER SERVICE ELECTRIC HEATING RATE RATE CODE 401-447	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 2 OF 3

MONTHLY RATE for Rate Code 401-423:

CUSTOMER ACCESS CHARGE:	$	420.00	per Billing Cycle		
FACILITIES CHARGE:					
Secondary Service	$	3.50	per kW		
Primary Service	$	2.95	per kW		
Substation Service	$	1.03	per kW		
DEMAND CHARGE:					
All kW	$	9.90	per kW		
ENERGY CHARGE:		**SUMMER**		**WINTER**	
First 300 kWh per kW	$	0.02211	$	0.02211	per kWh
All Additional kWh	$	0.01099	$	0.00360	per kWh

MINIMUM BILL:
The Monthly Customer Charge plus the Facilities Charge plus any Demand Charge.

FACILITIES DEMAND:
The Facilities Demand shall be equal to the greater of the contract demand or highest metered 30-minute Demand occurring in the current month or the preceding eleven (11) months. In no event shall the Facilities Demand be less than the customer's contract demand.

BILLING DEMAND:
The billing demand during the summer months of June through September shall be the larger of the contract demand (as mutually agreed upon) or the greatest average kilowatt demand measured in any 30-minute period during the month. The billing demand during the winter period shall be the lesser of the largest billing demand during the current month or 70% of the largest billing demand during the aforementioned Summer months.

METERING OPTION:
At the Utility's option, suitable metering equipment may be installed on the secondary side of the transformer.

ELECTRIC RATE SCHEDULE		
LARGE POWER SERVICE ELECTRIC HEATING RATE RATE CODE 401-447	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 3 OF 3

METERING ADJUSTMENT:
The monthly demand and energy charges are based on primary metering. When a secondary, substation or transmission meter is installed which does not compensate for transformer losses, the customer's metered kWh's and kW will be adjusted as follows:

SECONDARY	Increased by 2.0%
PRIMARY	Increased by 0%
SUBSTATION	Decreased by 2.8%
TRANSMISSION	Decreased by 3.3%

TRANSFORMER RENTAL:
Customers may, upon the approval of the Board, rent their service transformers and related equipment for a monthly fee equivalent to the cost of providing and maintaining these facilities. Any customer receiving a Primary, Substation, or Transmission Metering Adjustment will be required to own or rent its service transformers and related equipment behind the metering point.

TERM OF CONTRACT:
12 months for service under any provisions of this schedule.

APPLICABLE RIDERS:
El Energy Rate Component Rider
E2 Payment-In-Lieu-Of-Tax
E7 Reactive Adjustment
E16 Electric Rate Stabilization Rider
E17 Environmental Surcharge Rider

RATE CODE:	**401**
EFFECTIVE:	**7/1/2023**
SUPERSEDES RATE EFFECTIVE:	**1/1/2018**

ELECTRIC RATE SCHEDULE		
LARGE POWER HIGH LOAD FACTOR RATE RATE CODE 450	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 2

AVAILABILITY:
At any point on the Board's existing system having adequate capacity and suitable voltage for secondary, primary or substation voltage level of service.

APPLICATION:
For service to customers having a demand of 4,001 kW or greater at least once in any given 12-month period or new loads estimated to reach at least 4,001 kW within two years and maintaining a monthly billing load factor of at least 550 hours use per kW for at least nine of the last twelve months, including the current month. If the customer fails to meet this requirement the account will be billed under the Large Power Service Rate for at least one year. In the event that a customer has a demand of at least 4,001 kW and elects to be served under this rate, the rate shall be applied for a period of at least one year. The Board may require a minimum contract demand for new customers.

CHARACTER OF SERVICE:
Service will be at three-phase, 60 cycles at a standard delivery voltage as available at customer's service location. Service requested by customer at other voltages will be provided in accordance with the Board's Rules and Regulations.

MONTHLY RATE for Rate Code 450:

CUSTOMER CHARGE:	$	420.00	per Billing Cycle
FACILITIES CHARGE:			
Secondary Service	$	3.50	per kW
Primary Service	$	2.95	per kW
Substation Service	$	1.03	per kW
DEMAND CHARGE:			
All kW	$	18.11	per kW

MINIMUM BILL:
The Monthly Customer Charge plus the Facilities Charge plus any Demand Charge.

FACILITIES DEMAND:
The Facilities Demand shall be equal to the greater of the contract demand or highest metered 30-minute Demand occurring in the current month or the preceding eleven (11) months. In no event shall the Facilities Demand be less than the customer's contract demand.

ELECTRIC RATE SCHEDULE		
LARGE POWER HIGH LOAD FACTOR RATE RATE CODE 450	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 2 OF 2

BILLING DEMAND:
The billing demand during the summer months of June through September shall be the larger of the contract demand (as mutually agreed upon) or the greatest average kilowatt demand measured in any 30-minute period during the month. The billing demand during the winter period shall be the greater of the largest billing demand during the current month or 70% of the largest billing demand during the aforementioned summer months.

METERING OPTION:
At the Utility's option, suitable metering equipment may be installed on the secondary side of the transformer.

METERING ADJUSTMENT:
The monthly demand and energy charges are based on primary metering. When a secondary, substation or transmission meter is installed which does not compensate for transformer losses, the customer's metered kWhs and kW will be adjusted as follows:

SECONDARY	Increased by 2.0%
PRIMARY	Increased by 0%
SUBSTATION	Decreased by 2.8%
TRANSMISSION	Decreased by 3.3%

TRANSFORMER RENTAL:
Customers may, upon the approval of the Board, rent their service transformers and related equipment for a monthly fee equivalent to the cost of providing and maintaining these facilities. Any customer receiving a Primary, Substation, or Transmission Metering Adjustment will be required to own or rent its service transformers and related equipment behind the metering point.

TERM OF CONTRACT:
12 months for service under any provisions of this schedule.

APPLICABLE RIDERS:

El	Energy Rate Component Rider
E2	Payment-In-Lieu-Of-Tax
E7	Reactive Adjustment
E16	Electric Rate Stabilization Rider
E17	Environmental Surcharge Rider

RATE CODE:	**450**
EFFECTIVE:	**7/1/2023**
SUPERSEDES RATE EFFECTIVE:	**1/1/2018**

ELECTRIC RATE SCHEDULE		
PRIVATE AREA LIGHTING & TRAFFIC SIGNAL RATE RATE CODE 700	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 2

AVAILABILITY:
At any point on the Board's existing distribution system.

APPLICATION:
For lighting and signal service billed on a single monthly charge and generally based upon unmetered use.

EQUIPMENT:
BPU will install, own and operate the following items designated as standard equipment.

MONTHLY RATE:

1. Private Area Lighting:

RATE CODE	PRIVATE AREA LIGHTING	MONTHLY CHARGE	ESTIMATED MONTHLY kWh
701	175 Watt Mercury Vapor*	$ 16.64	63
702	400 Watt Mercury Vapor*	$ 24.97	151
703	400 Watt Mercury Vapor (Power Flood)*	$ 29.58	151
704	1,000 Watt Mercury Vapor*	$ 51.11	361
705	705-1,000 Watt Mercury Vapor (Power Flood)*	$ 60.29	361
706	70 Watt High Pressure Sodium	$ 17.45	25
707	250 Watt High Pressure Sodium	$ 20.07	104
708	250 Watt High Pressure Sodium (Power Flood)	$ 30.48	104
709	400 Watt High Pressure Sodium*	$ 55.21	151
710	400 Watt High Pressure Sodium (Power Flood)	$ 64.45	151
711	70 Watt High Pressure Sodium (Power Flood)	$ 25.06	25
712	50 Watt LED	$ 13.73	18
713	100 Watt LED Streetlight	$ 16.48	37
714	250 Watt LED Decorative Post Combo	$ 24.17	93
715	250-400 Watt LED Flood	$ 32.44	150

* New installations of the following have not been available since December 29, 1998. The decision to repair or replace these installations with another type shall be BPU's option.

RATE CODE	ADDITIONAL FACILITIES	MONTHLY CHARGE
730	35 Foot Wooden Pole	$ 6.34
731	26 Foot Steel Pole and Base	$ 14.50
732	Additional Span of Wire (170 Ft. Max)	$ 1.40

ELECTRIC RATE SCHEDULE		
PRIVATE AREA LIGHTING & TRAFFIC SIGNAL RATE RATE CODE 700	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 2 OF 2

2. Other Exterior Metered and Non-Metered Lighting:

For photo-cell controlled exterior lighting devices and metered lighting use. If the lighting use is unmetered and the lighting device is photo-cell controlled, then the kWh use shall be based upon the total connected wattage and 333 hours use per month.

RATE CODE				
750	Public Metered Lighting	$	0.12408	per kWh
751	Municipal Lighting	$	0.03525	per kWh
752	KS Dept of Transportation	$	0.10585	per kWh

3. Traffic and Railroad Signal:

RATE CODE				
760	Traffic and Railroad Signals	$	3.44	per service

APPLICABLE RIDERS:

El Energy Rate Component Rider
E2 Payment-In-Lieu-Of-Tax
E16 Electric Rate Stabilization Rider

RATE CODE:	**700-760**
EFFECTIVE:	**7/1/2023**
SUPERSEDES RATE EFFECTIVE:	**1/1/2018**

ELECTRIC RATE RIDER		
OUTDOOR EVENT LIGHTING	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 2

AVAILABILITY:
Available to all general service customers as a Rider to a customer's primary rate schedule where separately metered event outdoor field lighting application is used for no more than 60 event days per calendar year. In cases where the customer has multiple meters serving its facility the primary rate schedule shall be defined as the rate schedule under which the outdoor event lighting was billed prior to being separately metered. Outdoor lighting means facilities used to illuminate the event locale including the event venue (field, track, or other event locale), stadium lighting for the event and other lighting used exclusively for events at the locale that can be separately metered as provided below provided that the separately metered lighting is not used for more than 60 event days within a calendar year.

APPLICATION:
Separately metered, or sub-metered to standards of BPU, customer-owned and controlled outdoor field lighting for public events occurring on a scheduled basis. The customer and BPU may determine a minimum contract demand for the lighting application if appropriate.

EQUIPMENT:
The customer will install the necessary equipment in accordance with BPU's review and design approval to permit BPU to separately meter the event outdoor field lighting. Where BPU approves sub metering of the lighting application the sub-metered actual demand and energy quantities shall be subtracted from the actual metered quantities used in determination of charges under the primary rate schedule.

MONTHLY RATE:

CUSTOMER CHARGE:	$ 51.25 per Meter per Billing Cycle
FACILITIES CHARGE:	Billed in accordance with the customer's applicable rate schedule.
DEMAND CHARGE:	Billed at 60% of the Demand Rate in the customer's applicable rate schedule.
ENERGY CHARGE:	Billed at the 'All Additional kWh' Rate in the customer's applicable rate schedule.

ELECTRIC RATE RIDER		
OUTDOOR EVENT LIGHTING	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 2 OF 2

MINIMIUM BILL:
The Monthly Customer Charge plus the Facilities Charge plus any Demand Charge.

FACILITIES DEMAND:
The Facilities Demand shall be equal to the greater of the contract demand or highest metered 30-minute Demand occurring in the current month or the preceding eleven (11) months. In no event shall the Facilities Demand be less than the customer's contract demand.

BILLING DEMAND:
The billing demand shall be the larger of the contract demand (as mutually agreed upon) or the greatest average kilowatt Demand measured in any 30-minute period during the month.

APPLICABLE RIDERS:

El	Energy Rate Component Rider
E2	Payment-In-Lieu-Of-Tax
E16	Electric Rate Stabilization Rider
E17	Environmental Surcharge Rider

OUTDOOR EVENT LIGHTING	
EFFECTIVE:	7/1/2023
SUPERSEDES RATE EFFECTIVE:	1/1/2018

ELECTRIC RATE RIDER		
ENERGY RATE COMPONENT RIDER E1	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 3

PURPOSE:
The purpose of this rider is to provide for recovery of the Utility's power supply costs not recovered in the Base Monthly Charges, with a reconciliation adjustment that provides for the treatment of over/under recoveries for each quarter period.

APPLICABILITY:
Applicable to all electricity billed under any of the Board's electric rate schedules whether metered or unmetered.

ENERGY RATE COMPONENT:
The Utility shall recover its power supply costs by multiplying the Customer's electricity use for billing purposes under the Board's electric rate schedules in a billing period, by the Energy Rate Component (ERC) for the billing period, expressed in dollars per kilowatt hour, as calculated below by calendar quarter periods.

1. Calculation: The formula for calculating the energy rate component (ERC) is:

$$ERC = \frac{PPC + RA + RF}{S}$$

Where:

PPC = Projected power supply costs by calendar quarter period as defined below, expressed in dollars.

RA = Reconciliation adjustment by calendar quarter period as defined below, expressed in dollars.

RF = ERC Reserve Fund adjustment.

S = Projected sales of electricity by calendar quarter period as defined below, expressed in kilowatt-hours (kWh).

2. Definitions:

PC = Power supply costs, by calendar quarter period, which is:

(a) The sum of:
- (i) all fossil fuel costs including all energy-related costs incurred by reason of using fossil fuel and expensed to the BPU account which is the equivalent to FERC Account 501,
- (ii) all delivered costs of re-agents necessary to use in conjunction with fuel consumed for plant generation. This includes lime and the associated freight, ammonia, and other chemicals,

ELECTRIC RATE RIDER		
ENERGY RATE COMPONENT RIDER E1	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 2 OF 3

(iii) all purchased power energy costs expensed in the BPU account which is the equivalent to FERC Account 555 and BPU's charges or credits incurred due to participation in markets associated with the Regional Transmission Organizations (RTOs),

(iv) that portion of purchased power demand costs expensed in the BPU account which is the equivalent to FERC Account 555 and BPU's charges or credits incurred due to participation in markets associated with the RTOs which does not constitute the Base Rate Purchase Capacity (BRPC), as defined below, allocable to such calendar quarter period,

(v) all transmission costs payable to others for the transmission of the utility's electricity over transmission facilities owned by others, expensed in the BPU account which is the equivalent to FERC Account 565 and the RTO, FERC, NERC and other third-party costs expensed in the BPU account which is the equivalent to FERC Accounts 560, 561.4, 561.8, 575.7 and Account 928,

(vi) the cost of emission allowances and Renewable Energy Certificates (RECs) required to meet BPU's retail requirements and expensed in the BPU account which is the equivalent to FERC Account 509, and

(vii) all demand response costs which give the Utility dispatchable control of customer load for peak shaving, not otherwise recovered in the rates,

(b) Less the sum of:

(i) fossil fuel and purchased power costs recovered through all inter-system sales of energy, and

(ii) the value of emission allowances and RECs net of any brokerage fees sold in the market and entered as a negative expense in the BPU account which is the equivalent to FERC Account 509, expressed in dollars.

PPC = Projected PC, by calendar quarter period, for the projection period.

APC = Actual PC, by calendar quarter period, for the calendar quarter period which ended 3 months previously.

BRPC = Base Rate Purchase Capacity is that annualized amount of demand and capacity charges included in the Base Monthly Charges, of which annualized amount, one fourth shall be allocable to each calendar quarter period for purposes of this Rider. The annualized amount is the annual sum of long-term purchase power demand or capacity charges under agreements that have a term greater than one year in length and that are known at the time of the most recent base rate case. The annualized amount of such charges as of the effective date set forth below is $4.643 million.

B = Projected sales of electricity, by calendar quarter period, under all of the Board's retail rate schedules, whether metered or unmetered, for the projection period, expressed in kilowatt-hours (kWh).

ELECTRIC RATE RIDER		
ENERGY RATE COMPONENT RIDER E1	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 3 OF 3

RA = APC, plus the historical over/under collection from previous quarter periods, less the revenue collected from the ERC applied during the calendar quarter period which ended 3 months previously.

The Calendar quarter periods shall be:

First Quarter	-	January through March
Second Quarter	-	April through June
Third Quarter	-	July through September
Fourth Quarter	-	October through December

Renewable Energy Certificate (REC), is a tradable, intangible energy commodity in the United States that represents proof that one (1) megawatt-hour (MWh) of electricity was generated from an eligible renewable energy resource (renewable energy).

The Utility shall review the ERC calculation and reconciliation adjustment and make projections for each calendar quarter period. Based on each calendar quarter period review and projections the Utility may make adjustments to the ERC to be applied during the ensuing quarter period. The Utility may also make adjustments to the ERC to be applied during the ensuing quarter period to accomplish other purposes including but not limited to minimizing ERC volatility.

RF = The Utility maintains an ERC Reserve Fund equal to 120 days of annual expenses recovered in the ERC. The RF adjustment is the mechanism to fund the ERC Reserve through the ERC. If the ERC Reserve is not fully funded to 120 days of annual ERC expense, the RF adjustment will be limited to a maximum of $3,000,000 in any calendar quarter.

ELECTRIC RATE RIDER		
ELECTRIC PAYMENT TO CITY IN-LIEU-OF TAX RIDER RIDER E2	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 1

APPLICATION:
To all customers (wholesale and retail) from which the Board of Public Utilities (BPU) of the City of Kansas City, Kansas is required to collect or remit a percentage of revenue as a payment "in-lieu-of-tax" to the Unified Government of Wyandotte County/Kansas City, Kansas or to any other agency having authority to impose a gross receipts tax or fee on the sale of electricity.

BILLING:
Billings for payment of this "in-lieu-of-tax" or such other fees shall be included with the regular billings for electric service and shall be an amount sufficient to compensate the BPU for any amount it is required to collect or remit.

AMOUNT:
The amount of "in-lieu-of-tax" or such other fees as may be imposed or required to be paid shall be calculated as follows:

T = the total amount of "in-lieu-of-tax" = (B)(r)

where:

B = amount of bill as calculated in accordance with the effective rate excluding any gross receipts taxes.

r= the "in-lieu-of-tax" (or such other fee) rate applicable to the billing. As of January 1, 2023, the rate is 11.9 percent. The Unified Government of Wyandotte County/Kansas City, Kansas establishes the "in-lieu-of-tax" as outlined in its Charter Ordinance. The ordinance states the "in-lieu-of-tax" can be no less than 5 percent and no more than 15 percent of gross revenues.

OTHER PROVISIONS:
All terms and conditions in conflict herewith are hereby superseded, otherwise all terms and conditions of the currently applicable rate schedules shall remain in full force and effect.

ELECTRIC PAYMENT TO CITY IN-LIEU-OF TAX	
EFFECTIVE:	1/1/2023
SUPERSEDES RATE EFFECTIVE:	1/1/2022

ELECTRIC RATE RIDER		
REACTIVE ADJUSTMENT RIDER RIDER E7	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 1

PURPOSE:
The rates and charges in the Small General Service, Medium General Service, Large General Service and Large Power Rate Schedules are based on the customer maintaining a Power Factor, lagging or leading, within 90%. Customers with low Power Factor can improve their Power Factor to within 90% by the installation of corrective equipment or altering the operation of customers' equipment. Customers with a low Power Factor cause the Utility to increase its generation, transmission, distribution and transformer capacity, and to incur additional system losses, in order to handle customers with a low Power Factor. The purpose of this Rider is to apply a Power Factor penalty to low Power Factor customers that don't improve their Power Factor thereby passing through the additional costs to be incurred by the Utility to the customer.

APPLICATION:
Applicable to all Small General Service, Medium General Service, Large General Service or Large Power Service (Rate Codes 200-451) customers where Utility metering measures customer's reactive power or Power Factor.

POWER FACTOR PENALTY:
A Power Factor penalty will be applied to customers that do not maintain a Power Factor, leading or lagging, within 90%. The Power Factor penalty will be calculated by multiplying the customer's monthly billing for Facilities, Demand and Energy Charges by the Power Factor penalty percentage. The Power Factor penalty percentage, for customers that do not maintain their Power Factor within 90%, will be the difference between the customer's monthly Power Factor and 90%.

CUSTOMER POWER FACTOR IMPROVEMENT:
Customers should install, at their expense, such corrective equipment and operate their facilities so as to maintain a Power Factor, leading or lagging, within 90%. A Power Factor penalty, as set forth above, will be applied to the monthly billings of customers that do not maintain a Power Factor within 90%. Power Factor less than 80%, lagging or leading, will not be permitted and the customer will be required to install at their own expense such corrective equipment as may be necessary to improve their Power Factor.

REACTIVE ADJUSTMENT	
EFFECTIVE:	**11/1/2003**
SUPERSEDES RATE EFFECTIVE:	**1/1/2002**

ELECTRIC RATE RIDER		
ELECTRIC RATE STABILIZATION RIDER RIDER E16	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 2

APPLICATION:
To all full-requirement customers, retail and wholesale, an increase to collect revenues in an amount sufficient to pay or recover expenditures for the payment of qualified expenditures that are material, as described below.
This rider shall only be applied in appropriate circumstances, including but not limited to, situations where the Utility has a need for revenues recovered under the rider that cannot be timely recovered through other means, situations where the Utility is suffering an operating cash shortage, situations where failure to apply the rider would result in economic loss or other financial harm to the Utility, emergency situations and other situations where the application of this rider to recover a qualified expenditure is in the best interests of the Utility as determined by the Board.

QUALIFIED EXPENDITURES:
For purposes of this rider, qualified expenditures are unanticipated or unusual electric operations expense items, unanticipated or unusual operation and maintenance expenses and contingencies of the Utility System, including the costs of scheduled, emergency or other interchange service, costs of unanticipated or unusual renewals and replacements to the Utility System, costs of emergency repairs to the Utility System and any cost with respect to the prevention or correction of any unanticipated or unusual loss or damage in connections with the Utility System or to prevent loss of revenues, including but not limited to the recovery of expenditures for such items from the Rate Stabilization Fund or the Improvement and Emergency Fund. A qualified expenditure will be considered material if the combined amounts for all events within a 12-month period equal or exceed $1,000,000. A qualified expenditure does not include any expenditure which the Utility has otherwise paid or recovered through the application of a rate schedule or rider or through other means such as reimbursement through insurance or disaster assistance.

IMPLEMENTATION OF RIDER; BILLING:
The Utility shall cause notice of a proposed application of this Rider to be published no less than 21 days prior to the date on which the recommendation will be presented to the Board for approval, and shall further cause notice to be provided to any Utility customer which has intervened in a rate proceeding within the past three years. Such notice shall include a description of the qualified expenditures and the proposed amortization period for collection of revenues to pay or recover the qualified expenditures. Any affected Utility customer may provide comments to the Utility and/or the Board relating to the proposed application of the rider, amortization period and surcharge methodology.

The Charges under each rate schedule shall be increased in any fiscal year(s) by the percentage(s) or amount(s) determined upon recommendation by the General Manager and approval by the Board as necessary to pay or recover qualified expenditures in an amount approved by the Board as described herein such fiscal year(s), such increase to take effect commencing upon approval, or at a date set, by the Board, over the reasonable amortization period established by the Board.

ELECTRIC RATE RIDER		
ELECTRIC RATE STABILIZATION RIDER RIDER E16	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 2 OF 2

The Charges under each rate schedule assessed under this rider shall be an equal percentage adjustment to non-Energy Rate Component charges to recover the qualified expenditures over the amortization period, unless the Board shall approve a different surcharge methodology.

AMOUNT:
The amount of revenues to be collected shall be sufficient to provide for payment or recovery of qualified expenditures over the amortization period established by the Board.

ELECTRIC RATE STABILIZATION	
EFFECTIVE:	1/1/2007
SUPERSEDES RATE EFFECTIVE:	7/1/2002

ELECTRIC RATE RIDER		
ENVIRONMENTAL SURCHARGE RIDER RIDER E17	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 3

PURPOSE:
The purpose of this Rider is to provide for the annual recovery of the Utility's capital investment in projects that are required to meet Federal, State or Local environmental regulations. All such costs shall be accounted for separately and shall be the basis for the rider discussed below.

APPLICABILITY:
Applicable to all retail electric customers billed under any of the Board's electric rate schedules whether metered or unmetered.

BILLING:
Billing for this surcharge shall be included with the regular billings for electric service as a separate line item on the bill in an amount sufficient to compensate the BPU for any dollar amount expended on required environmental capital projects, plus applicable debt service coverage, for retail customers.

AMOUNT:
The amount of Environmental Surcharge Rider (ESC) to be paid by retail customers shall be calculated pursuant to the following formula:

Total Cost = ECC +/- RA for the current year where

ECC = Environmental Capital Costs for the projected 12 month period starting January 1 and ending December 31, expressed in dollars, as recorded in the accounts of the BPU and not recovered through the application of a rate schedule or rider or through other means such as reimbursement through government assistance. Environmental capital costs shall be the sum of: (i) debt service payments (principal plus interest), plus debt service coverage in the amount of 0.3 times the debt service payments in the projected 12 month period on material environmental capital projects which have been or are projected to be debt financed in the projected 12 month period, plus (ii) that portion of cash expenditures associated with material environmental capital projects which has been or is projected to be debt financed which are to be recovered in the projected 12 month period as described herein, to the extent that such cash expenditures associated with such projects will not be debt financed, less (iii) debt service payments plus debt service coverage in the amount of 0.3 times the debt service payment or cash expenditures on such material environmental capital projects that are projected to be recovered from Participation or other non-retail customers in the projected 12 month period.

Cash expenditures associated with material environmental capital projects included in an application of this rider may include projected cash expenditures for the projected 12 month period, subject to reconciliation of projected to actual expenditures at the end of the 12 month period, and may also include cash expenditures incurred in connection with such material environmental capital projects which have not been recovered under this rider or otherwise. Recovery of cash expenditures may be amortized over more than one year. No more than 25% of the total cost of a material environmental

ELECTRIC RATE RIDER		
ENVIRONMENTAL SURCHARGE RIDER RIDER E17	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 2 OF 3

capital project or projects will be recovered under this Rider to pay cash expenditures associated with such project. An environmental capital project or projects will be considered material if (a) the cost of such project equals or exceeds $10,000,000, (b) the utility is required to make similar capital investments for environmental projects to more than one plant or generating unit to satisfy an environmental regulation and the aggregate cost of such environmental capital investments to such plants or generating units equals or exceeds $10,000,000, or (c) the utility is required to make capital investments for related environmental projects to one or more plant or generating units, to satisfy related environmental regulations, and the aggregate costs of such environmental capital investments equals or exceed $10,000,000.

RA = Reconciliation Adjustment expressed in dollars. The actual ECC for the most recent prior 12 month period starting January 1 and ending December 31, less the actual ESC revenue billed for the same period, plus or minus the historical over/under collection from previous years.

The charge applicable to each rate schedule shall be calculated by multiplying the Total Cost times the rate schedule production capacity allocation formula percentage as determined in the most recent rate setting procedure and set forth in the following table:

Table of Production Capacity Allocation Formula Percentages

Rate Schedule		Allocation Percentage
Rate Code	100-109	32.57%
Rate Code	200-223	10.69%
Rate Code	250-263	23.77%
Rate Code	300-323	8.38%
Rate Code	400-451	21.30%
Rate Code	500-599	3.28%

The charge applicable to each rate schedule shall equal the Total Cost times the production capacity allocation formula percentage divided by the twelve months billing units ending three months prior to the effective date of the new adjustment which shall be expressed in kWh for Rate Codes 100, 101, 200-223 and 500-599. For all other Rate Codes the billing units shall be expressed in kW of billing demand. Rate Codes 700-799, Private Area Lights are included and recovered in Rate Codes 100-101 and 200-223 equally.

ELECTRIC RATE RIDER		
ENVIRONMENTAL SURCHARGE RIDER RIDER E17	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 3 OF 3

BASIS OF ADJUSTMENT:
The calculation of the actual ESC shall be determined in the fourth quarter of each calendar year and applied to customer bills beginning January 1 of the following calendar year. The Utility shall give notice to the Board of the ESC amount for the following 12-month period, and shall provide annual reports to the Board of its collections including a calculation of the total revenue collected and expenditures made under this Rider.

IMPLEMENTATION OF RIDER
For any application of the Rider, the Utility shall cause notice of a proposed application of this Rider to a material environmental capital project(s) to be published no less than 120 days prior to the date on which the recommendation will be presented to the Board for approval, and shall further cause notice to be provided to any Utility customer which has intervened in a rate proceeding within the past three years.

Such notice shall include a description of the material environmental capital project(s), the estimated cost of the material environmental capital project(s) and anticipated amount thereof to be debt financed, and the anticipated amortization period for collection of revenues to pay or recover the cost of the material environmental capital project(s). Any affected Utility customer may provide comments to the Utility and/or the Board relating to the proposed application of the Rider. The Rider shall be applied to a material environmental capital project(s) upon approval by the Board. No additional notice or approval shall be required following the initial Board determination that the Rider shall be applied to recover the costs of a material environmental capital project(s).

ENVIRONMENTAL SURCHARGE	
EFFECTIVE:	**7/1/2023**
SUPERSEDES RATE EFFECTIVE:	**3/1/2017**

ELECTRIC RATE RIDER		
GREEN ENERGY RIDER RIDER E18	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 3

AVAILABILITY:
Electric service under this Program is only available to Customers currently served by the Board of Public Utilities ("Utility") under the Large General Service Rate 300-322, Large General Service Electric Heating Rate 301-323, Large Power Service Rate 400-446, Large Power Service Electric Heating Rate 401-447, or Large Power High Load Factor Rate 450, service classification and who adequately demonstrate that they will purchase a minimum 10,000,000 kilowatt-hours of energy annually from BPU.

Customers will be eligible to participate in the process to purchase Environmental Attributes (EAs) for amounts of not less than 10,000,000 kilowatt-hours and not more than the Customer's annual expected energy usage.

This Rider Schedule applies to Customers who wish to achieve environmental sustainability goals by purchasing from BPU exclusive EAs associated with renewable energy that is either from facilities owned by BPU or procured by BPU through a Purchased Power Agreement (PPA).

BILLING COMPONENTS:

The Green Rider Charge will be determined Monthly

1. **Calculation: The formula for calculating the Green Rider Charge is:**

$$(kWh * RP) – (kWh * SPP\$)$$

Where:

RP = Resource Price per kilowatt-hour. The RP will include all costs associated with the additional renewable resources. In addition to the cost of the renewable generation, the RP will include all new transmission costs needed to transmit the renewable energy to market, integration costs, and administration costs.

kWh = The monthly kilowatt-hour equivalent produced by generator for which the Customer has contracted.

**SPP$** = The average monthly net of all revenues and costs assessed by the Southwest Power Pool Integrated Market at the Contracted Renewable Facility Settlement locations divided by the total kilowatt-hours to determine average SPP$ per kilowatt-hour. All revenues and charges will be allocated by settlement date and will include but will not be limited to the day-ahead, real-time, and distribution charges such as losses, revenue neutrality and make-whole payments.

Monthly Green Rider Charge may be a charge or a credit depending on the monthly net of all revenues and costs assessed by the SPP Integrated Market.

The monthly Green Rider Charge, whether a charge or a credit, are independent and will not affect the calculation of any bills received for services from BPU.

ADMINISTRATIVE:

1. Definitions:

Environmental Attributes (EAs): All current and future attributes of an environmental nature, including but not limited to allowances, certificates, emission credits and all other credits, offsets, green tags and all other tags, and all similar rights issued, recognized, created or otherwise resulting from the generation of energy using wind, sunlight, water, biological processes, or geothermal heat sources. EA's include but are not limited to, those attributes that are created or recognized by regulations, statutes, or other action by a governmental authority and include, but are not limited to, those attributes that can be used to:

- Claim responsibility for the reduction of emissions and/or pollutants.
- Claim Ownership of emission and/or pollutant reduction rights.
- Claim reduction or avoidance of emissions or pollutants.
- Claim compliance with a renewable energy standard or renewable portfolio standard.

2. Special Conditions:

The terms and conditions of the appropriate Rate Schedule apply to the service rendered.

Customers taking service under this Rider Schedule are purchasing EA's. Rights and/or claims to capacity, energy, Production Tax Credits, and/or Investment Tax Credits from renewable energy facilities are not being transferred or sold under this Rider Schedule.

BPU reserves the right to maintain a renewable portfolio based on market conditions and its ability to integrate the renewable energy into its portfolio on an economic basis.

Any renewable energy facilities developed to meet the Customer's requests under this Rider Schedule will be located with the SPP footprint.

If, prior to the end of the term of a given subscription, a Customer provides written notification of its election to terminate or reduce its RE Service for an account covered by a RE Service Agreement:

a. The Customer without penalty may transfer some or all of the RE Service to another account that is within the Utility's service territory and is either (i) currently not covered by an RE Service Agreement, or (ii) is covered by an RE Service Agreement for only a part of its eligible usage, in either case only to the extent the consumption at the new account under (i) or the eligible unsubscribed usage at an account that had already been receiving RE Service under (ii) is sufficient to accommodate the transfer; or

b. At Customer's written request, the Utility will attempt to find another interested Customer that meets the Utility's eligibility requirements and is willing to accept transfer of RE Service (or that part which cannot be transferred to another Customer account) for the remainder of the term of the subscription at issue; or

c. If option a) or b) is not applicable as to some or all the RE Service at issue, the Customer will continue to be obligated to pay for, or be eligible to receive, the Customer Monthly RE Adjustment as to that part of the RE Service that was not transferred; or

d. If option a) or b) is not applicable and in lieu of option c), the Customer may reduce or terminate RE Service for the account at issue upon payment of the Termination Fee, which is as follows: The average of the Customer's Monthly RE Adjustment for the preceding 12 months (or all preceding months, if less than 12) times the number of months remaining in the term; if this value is less than or equal to zero (e.g., a credit to Customer), then the Termination Fee is zero, and in no event shall the Customer receive a net credit from the Utility for reducing or terminating RE Service.

e. Failure to meet the requirements of options a), b), c) or d) will result in the forfeiture of all funds dedicated in the letter of credit or other security provision.

Customer must provide a letter of credit, surety bond or other form of security for payment of all costs. Security requirements will be determined on a case by case basis.

WATER RATE SCHEDULE		
MONTHLY WATER RATES FOR INSIDE & OUTSIDE CITY CUSTOMERS RATE CODE 010 & 020	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 1

Water sold to retail customers inside and outside city limits:

CCF Units Per Month	CCF Units Per Block	Rate per CCF
0 to 7 CCF	7	$ 4.22
8 to 2,000 CCF	1,993	$ 3.56
Over 2,000 CCF		$ 3.29
Hydrant Daily Fee		$ 1.50

MONTHLY CUSTOMER CHARGE	
Meter Size	EFFECTIVE 07/01/2023
5/8 Inch	$ 19.35
3/4 Inch	$ 24.05
1 Inch	$ 30.65
1.5 Inch	$ 49.40
2 Inch	$ 68.00
3 Inch	$ 150.50
4 Inch	$ 243.50
6 Inch	$ 477.00
8 Inch	$ 711.00
10 Inch	$ 944.00
12 Inch & Greater	$ 1,083.00

MONTHLY MINIMUM BILL (Inside & Outside City)		
Effective 07/01/2023		
Meter Size	Inside & Outside City	
	Dollars	Min. CCF
5/8 Inch	$ 19.77	0.10
3/4 Inch	$ 43.88	4.70
1 Inch	$ 61.97	7.50
1.5 Inch	$ 109.91	15.70
2 Inch	$ 163.40	25.50
3 Inch	$ 317.10	45.50
4 Inch	$ 511.56	74.00
6 Inch	$1,008.50	148.00
8 Inch	$1,596.72	247.50
10 Inch	$2,272.94	372.00
12 Inch & Greater	$2,734.12	462.50

APPLICABLE RIDERS:
W2 Payment-in-Lieu-of-Tax

WATER-INSIDE/OUTSIDE CITY	
EFFECTIVE:	07/01/2023
SUPERSEDES RATE SCHEDULE EFFECTIVE:	01/01/2013

WATER RATE SCHEDULE		
MONTHLY WATER RATES WHOLESALE WATER	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 1

WHOLESALE	
Rate Code 31, 32, 33, 34	
	Effective 07/01/2023
All Usage per CCF	$ 1.88
Montly Charge	$ 160.00

APPLICABLE RIDERS:
W2 Payment-in-Lieu-of-Tax

WHOLESALE WATER	
EFFECTIVE:	**07/01/2023**
SUPERSEDES WHOLESALE RATE EFFECTIVE:	**01/01/2013**

WATER RATE SCHEDULE		
MONTHLY WATER RATES PRIVATE FIRE PROTECTION RATE	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 1

Private Fire Protection Rates Montly Charge	
Rate Code 40	
Meter Size	Effective 07/01/2023
2 Inch	$ 7.97
4 Inch	$ 20.44
6 Inch	$ 49.86
8 Inch	$ 100.21
10 Inch	$ 175.95
12 Inch	$ 281.10

All water used through private fire connections for purposes other than fire protection shall be subject to the applicable Inside City or Outside City volume charge rates.

APPLICABLE RIDERS:
W2 Payment-in-Lieu-of-Tax

PRIVATE FIRE PROTECTION	
EFFECTIVE:	**01/01/2013**
SUPERSEDES RATE EFFECTIVE:	**01/01/2012**

WATER RATE RIDER		
WATER PAYMENT TO CITY IN-LIEU-OF TAX RIDER RIDER W2	BOARD OF PUBLIC UTILITIES KANSAS CITY, KANSAS	PAGE 1 OF 1

APPLICATION:
To all customers (wholesale and retail) from which the Board of Public Utilities (BPU) of the City of Kansas City, Kansas is required to collect or remit a percentage of revenue as a payment "in-lieu-of-tax" to the Unified Government of Wyandotte County/Kansas City, Kansas or to any other agency having authority to impose a gross receipts tax or fee on the sale of water.

BILLING:
Billings for payment of this "in-lieu-of-tax" or such other fees shall be included with the regular billings for water service and shall be an amount sufficient to compensate the BPU for any amount it is required to collect or remit.

AMOUNT:
The amount of "in-lieu-of-tax" or such other fees as may be imposed or required to be paid shall be calculated as follows:

T = the total amount of "in-lieu-of-tax" = (B)(r)

where:

B = amount of bill as calculated in accordance with the effective rate excluding any gross receipts taxes.

r= the "in-lieu-of-tax" (or such other fee) rate applicable to the billing. As of January 1, 2023, the rate is 11.9 percent. The Unified Government of Wyandotte County/Kansas City, Kansas establishes the "in-lieu-of-tax" as outlined in its Charter Ordinance. The ordinance states the "in-lieu-of-tax" can be no less than 5 percent and no more than 15 percent of gross revenues.

OTHER PROVISIONS:
All terms and conditions in conflict herewith are hereby superseded, otherwise all terms and conditions of the currently applicable rate schedules shall remain in full force and effect.

WATER TO PAYMENT TO CITY IN-LIEU-OF TAX	
EFFECTIVE:	01/01/2023
SUPERSEDES RIDER W2 EFFECTIVE:	01/01/2022

UNIFIED GOVERNMENT OF WYANDOTTE COUNTY / KANSAS CITY, KS RATES:

DESCRIPTION	ORDINANCE NO.	DOLLAR ($) AMT
SOLID WASTE FEE (TRASH)	O-130-22	$17.00
STORM WATER RESIDENTIAL (SWM)	O-122-21	$6.30 / mo
STORM WATER NON-RESIDENTIAL (SWM)	O-122-21	$14.70 / mo
PAYMENT-IN-LIEU-OF-TAXES (PILOT)	R-50-22	11.90%

REGULATION ESTABLISHING RATES FOR SEWER SERVICE CHARGES

Adopted Pursuant to Section 30-96 of the Code of the Unified Government of Wyandotte County/Kansas City, Kansas

Effective January 1, 2023

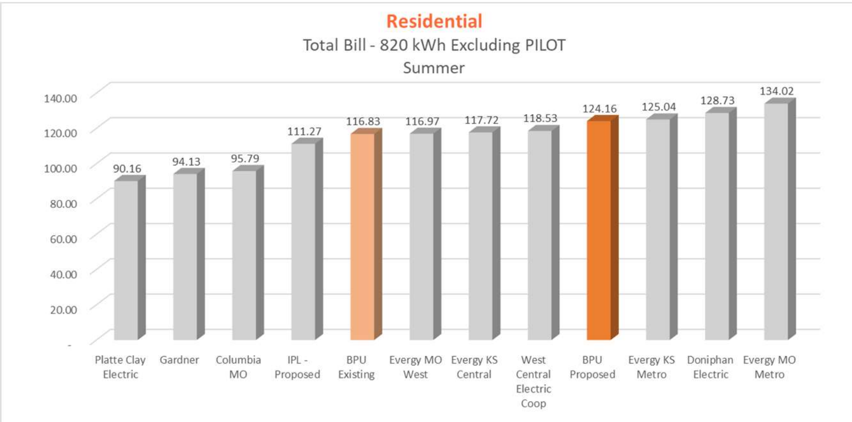
Water Pollution Abatement Rate Structure

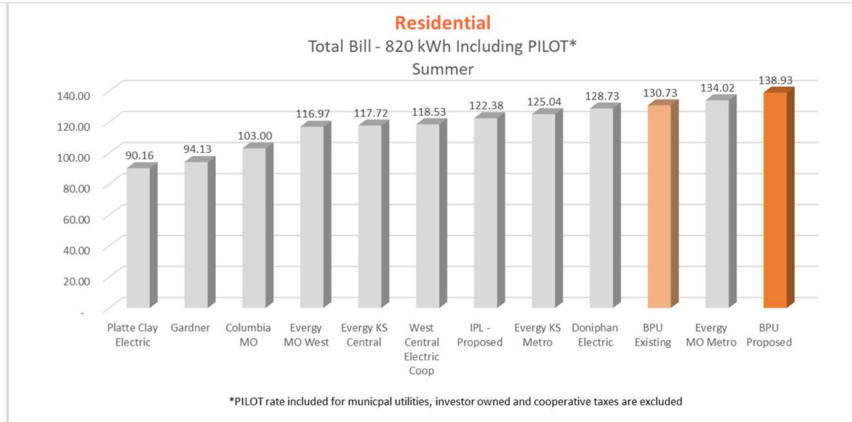
The rate structure is as follows:

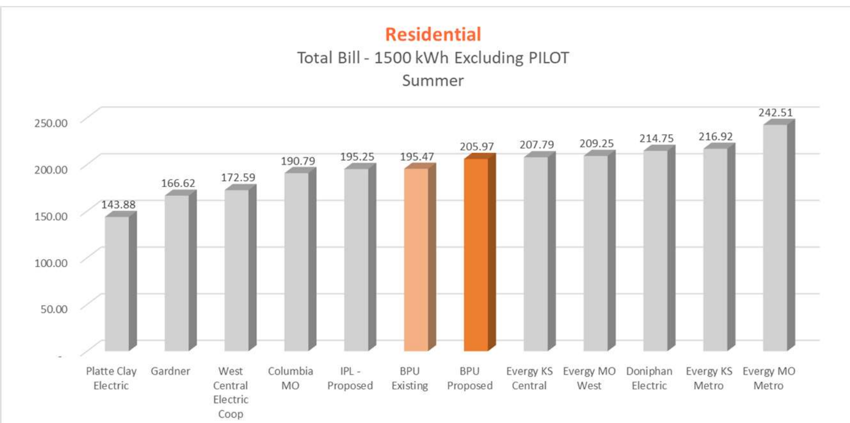
Water Pollution Abatement Rate Structure with 5% increase on January 1, 2023.	**2022**	**01/01/2023 5% Increase**
Monthly Base Charge	**$22.39**	**$23.51**
Unit Charges (per 100 cubic feet)		
Class IA	**$5.06**	**$5.31**
Class IB	**$5.06**	**$5.31**
Class II	**$6.81**	**$7.14**
(Restaurant (Food Establishment)		
Surcharges for Excess Loadings (Per Pound)		
TSS above 250mg/I	**$0.3960**	**$0.4158**
COD above 375 mg/I	**$0.2970**	**$0.3119**
O&G above 30mg/I	**$0.1395**	**$0.1465**
LPS Class 080A Monthly Add'l Charge	**$0.00**	**$0.00**

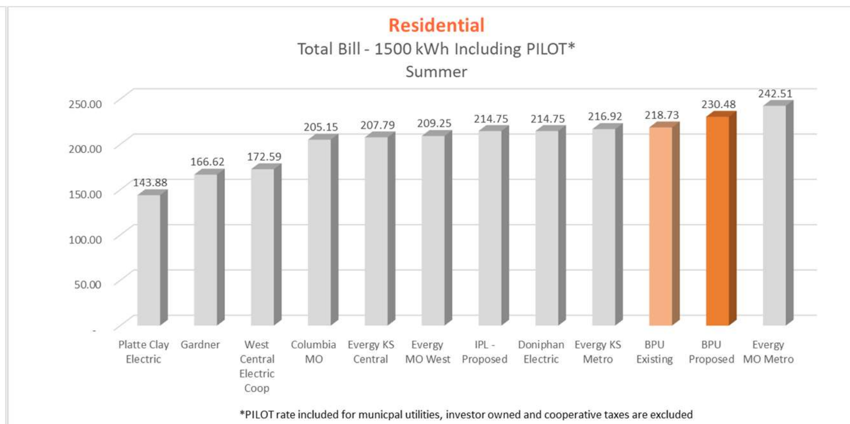
APPENDIX C – REGIONAL COMPARISION OF ELECTRIC RATES

C.1 Residential Rate Comparison – Summer

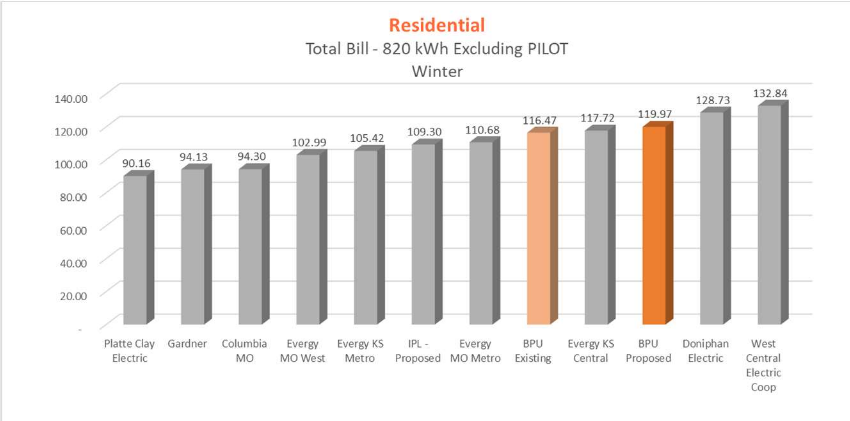


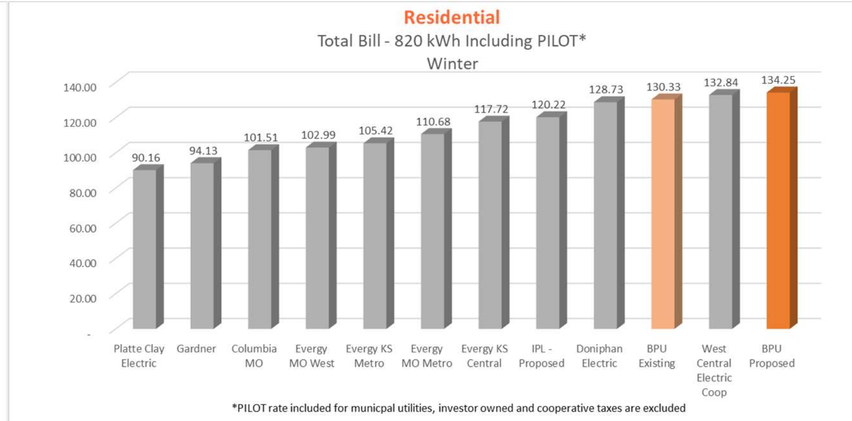


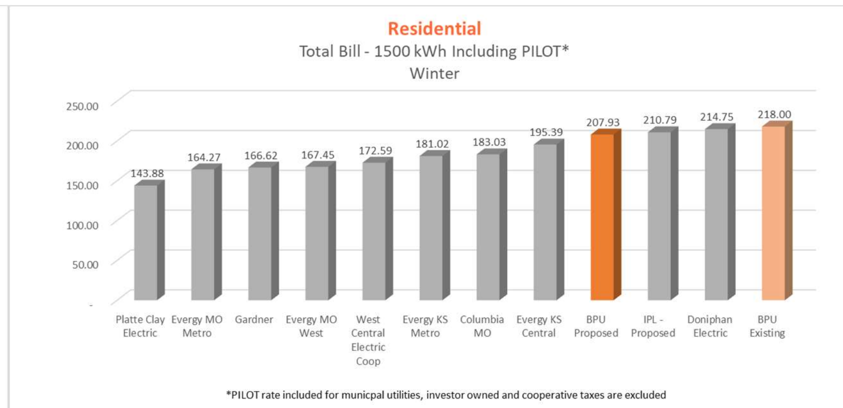




C.2 Residential Rate Comparison - Winter

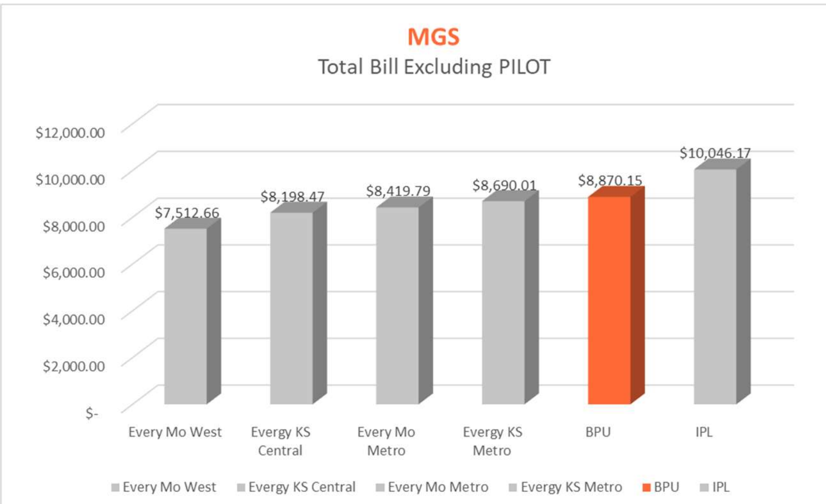


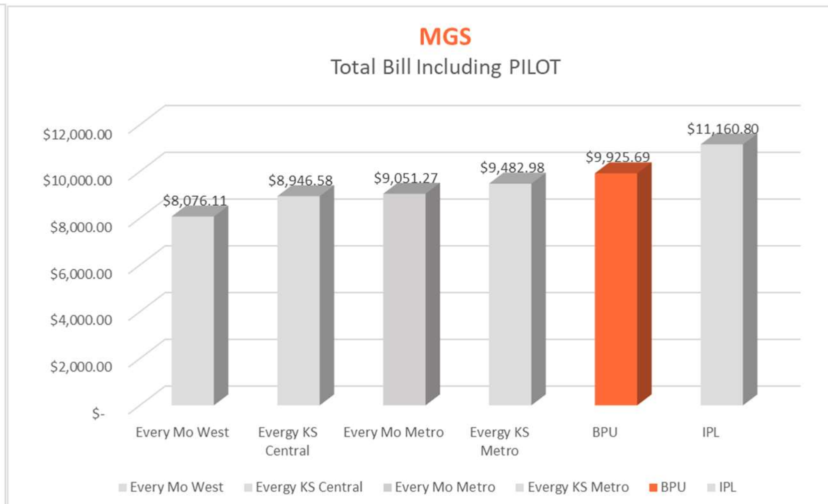




C.3 Medium General Service Rate Comparison – Average Monthly Bill

Provider	Customer Charge	Energy Charge	Demand Charge	Facilties Charge	Total Base Charges	Riders	Total Rate Charges	PILOT/Taxes	Total Bill
Every Mo West	$ 50.38	$ 5,364.05	$ 832.83	$ 735.00	**$ 6,982.26**	$ 530.40	$ 7,512.66	$ 563.45	**$ 8,076.11**
Evergy KS Central	$ 118.42	$ 971.87	$ 4,037.50	$ -	**$ 5,127.79**	$ 3,070.69	$ 8,198.47	$ 748.11	**$ 8,946.58**
Every Mo Metro	$ 112.65	$ 6,521.63	$ 692.17	$ 667.75	**$ 7,994.20**	$ 425.59	$ 8,419.79	$ 631.48	**$ 9,051.27**
Evergy KS Metro	$ 50.38	$ 5,364.05	$ 690.33	$ 735.00	**$ 6,839.76**	$ 1,850.25	$ 8,690.01	$ 792.96	**$ 9,482.98**
BPU	$ 95.00	$ 2,675.00	$ 1,737.50	$ 1,080.00	**$ 5,587.50**	$ 3,282.65	$ 8,870.15	$ 1,055.55	**$ 9,925.69**
IPL	$ 50.00	$ 5,610.37	$ 2,500.00	$ -	**$ 8,160.37**	$ 1,885.80	$ 10,046.17	$ 1,114.63	**$ 11,160.80**

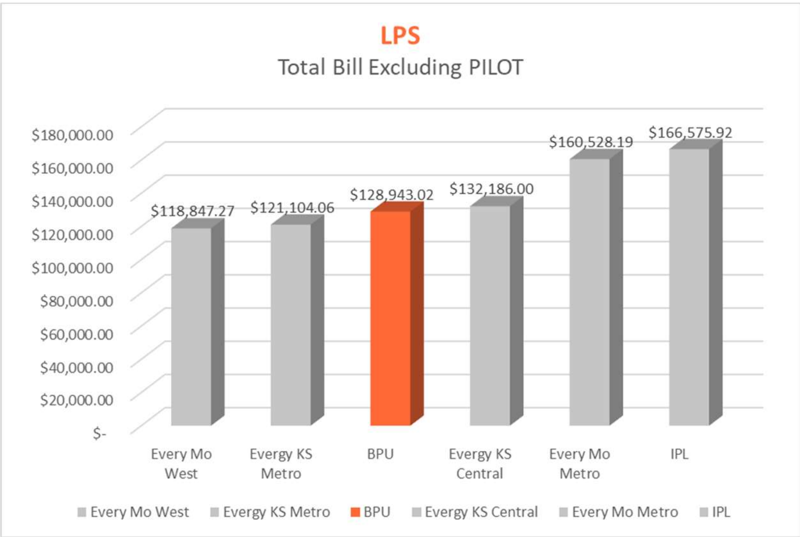


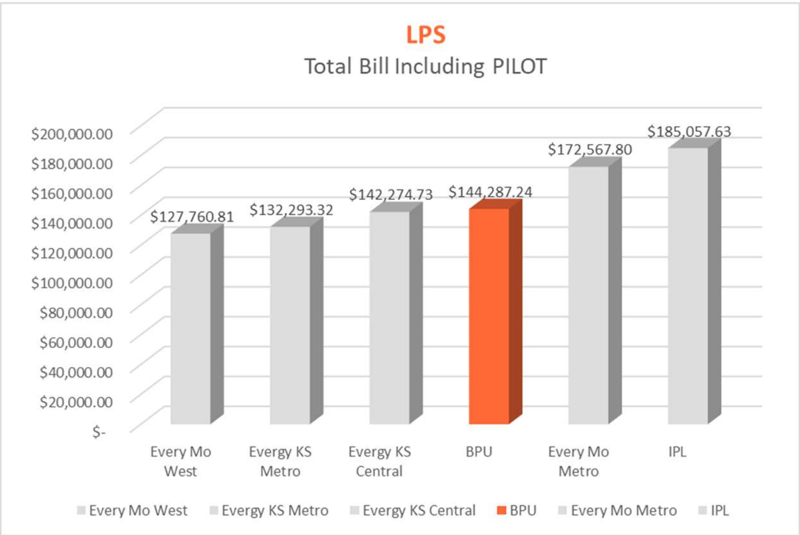


Average Monthly Bill Inputs	
kWh	80,000
kW	250

C.4 Large Power Service Rate Comparison – Average Monthly Bill

Provider	Customer Charge	Energy Charge	Demand Charge	Facilties Charge	Total Base Charges	Riders	Total Rate Charges	PILOT/Taxes	Total Bill
Every Mo West	$ 675.46	$ 62,215.20	$ 36,985.44	$ 14,503.50	**$ 114,379.60**	$ 4,467.67	$ 118,847.27	$ 8,913.55	**$ 127,760.81**
Evergy KS Metro	$ 724.76	$ 68,193.23	$ 20,013.00		**$ 88,930.99**	$32,173.06	$ 121,104.06	$ 11,189.26	**$ 132,293.32**
Evergy KS Central	$ 320.00	$ 17,946.50	$ 63,898.15		**$ 82,164.65**	$50,021.35	$ 132,186.00	$ 10,088.73	**$ 142,274.73**
BPU	$ 425.00	$ 26,425.57	$ 35,820.00	$ 15,750.00	**$ 78,420.57**	$50,522.45	$ 128,943.02	$ 15,344.22	**$ 144,287.24**
Every Mo Metro	$ 1,181.28	$ 91,401.27	$ 49,072.22	$ 17,802.00	**$ 159,456.77**	$ 1,071.42	$ 160,528.19	$ 12,039.61	**$ 172,567.80**
IPL	$ 50.00	$ 93,213.29	$ 38,250.00		**$ 131,513.29**	$35,062.63	$ 166,575.92	$ 18,481.71	**$ 185,057.63**





Average Monthly Bill Inputs	
kWh	1,300,000
kW	4,500

1898 & Co.

PART OF BURNS & McDONNELL

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Kansas City, MO

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1898andCo.com