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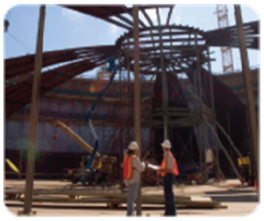



BOARD OF PUBLIC UTILITIES
KANSAS CITY, KANSAS

Electric Utility
Revenues, Revenue Requirements, Cost of Service, And Rates

Draft Final Report
(As Updated)

February 2010

BLACK & VEATCH
Building a world of difference.

February 1, 2010

Kansas City Board of Public Utilities
Mr. Don Gray, General Manager
540 Minnesota Avenue
Kansas City, KS 66101

Dear Mr. Gray:

We are pleased to present our Draft Final Report on *Electric Utility Revenues, Revenue Requirements, Costs of Service, and Rates* for the Kansas City Board of Public Utilities (BPU). An introduction and executive summary of the principal findings and recommendations precede the detailed text of the report.

We wish to acknowledge the cooperation and assistance of the BPU staff in providing guidance and information for the study. It is a pleasure to be of service to the BPU in this matter.

Very truly yours,

BLACK & VEATCH CORPORATION

Robert J. Brady
Director, Enterprise Management Solutions Division

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1.0 INTRODUCTION

The Kansas City Board of Public Utilities (BPU) owns and operates the electric power generation 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).

1.1 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. Black & Veatch designed utility rate studies encompass three principal steps, each intended to answer questions typically asked by Boards and utility management. These steps are:

- **Revenue Requirements** – What is the overall adjustment in rates needed to meet forecast cash requirements of the utility, meet debt service requirements, and maintain appropriate cash reserves?
- **Cost of Service** – What is each class's equitable share of the utility revenue requirements?
- **Rate Design** – How should rates be adjusted to reflect cost of service and remain sensitive to customer rate impacts?

1.2 Scope

This report presents the results of a comprehensive rate study of the electric utility and includes a financial projection of the utility for the five year period FY 2010 through FY 2014 to determine the overall adequacy of existing rates, a cost of service analysis, and rate recommendations for the utility.

The financial forecast of the electric utility reflects projections provided to Black & Veatch by the BPU and our analysis of trends in sales, revenues, and costs. Forecast operating conditions and cost levels for subsequent fiscal years recognize the amount and degree of service, cost of system expansion and replacement, prudent reductions in anticipated operating expenses and capital expenditures, anticipated cost escalations, continuation of the current policy on transfers to the City, and other factors relevant to the utility. Black & Veatch reviewed the financial projections and supporting assumptions provided by BPU and considers them appropriate for the purpose of forecasting revenue requirements and rates.

1.3 Disclaimer

Subject to the limitations set forth herein, this report was prepared for the Kansas City Board of Public Utilities (BPU) by Black & Veatch Corporation (B&V) and is based on information not within the control of B&V. B&V has not been requested to make an independent analysis, to verify the information provided to it, or to render an independent judgment of the validity of the information provided by others. As such, B&V cannot, and does not, guarantee the accuracy thereof to the extent that such information, data, or opinions were based on information provided by others.

B&V prepared this report in February 2010 based on information and conditions prevailing at that time. Any changes in that information or prevailing conditions may affect the conclusions, recommendations, assumptions, and forecasts set forth in this report. B&V makes no warranty, express or implied, regarding the reasonableness of any information, recommendation, or forecast set forth herein under any conditions other than those assumed in making such projections.

In conducting our analysis and in forming an opinion of the data summarized in this report, B&V has made certain assumptions with respect to conditions, events, and circumstances that may occur in the future. The methodologies utilized in performing the analysis and making the recommendations follow generally accepted industry practices. While it is believed that such assumptions and methodologies, as summarized in this report, are reasonable and appropriate for the purpose for which they are used; depending upon conditions, events, and circumstances that actually occur but are unknown at this time, actual results may materially differ from those shown. Such factors may include, but are not limited to, the regional and national economic climate and growth in the service area.

2.0 EXECUTIVE SUMMARY

Black & Veatch performed a comprehensive rate study for the electric utility of the BPU. With guidance from the BPU staff, our recommendations reflect three primary considerations: (1) fund the electric utility, to the degree practical, on a self-supporting basis; (2) phase-in the impact of rate adjustments to the utility; and (3) build and maintain appropriate cash reserve funds. Revenue projections under existing rates include the BPU approved rate adjustments for the electric utility effective January 1, 2007.

Based on a forecast of revenues under existing rates and revenue requirements for the utility for the period FY 2010 through FY 2014, we recommend a series of four 7 percent annual base rate increases for the utility, modifications to certain definitions and Riders in the Rate Manual, and the addition of an Environmental Surcharge (ESC) to recover the capital costs of environmental projects required to comply with environmental mandates. Recommended overall base rate revenue adjustments for the utility are shown in Table 2-1.

Table 2-1
Recommended Rate Adjustments

Description	Fiscal Year Ending December 31, 2010	2011	2012	2013	2014
Base Rates	7.0%	7.0%	7.0%	7.0%	0.0%
ESC	1.0%	1.6%	0.0%	0.0%	0.0%
Date Effective	June 1, 2010	January 1, 2011	January 1, 2012	January 1, 2013	

The recommended base rate adjustments are considered the *minimum level required* to maintain prudent financial operations of the BPU, appropriate debt service coverage ratios, and adequate reserve fund levels. Recently, Moody's Investors Service and Fitch Ratings placed negative outlooks on BPU's debt. The recommended base rate adjustments directly address the declining debt service coverage and reserve fund levels which contributed to the negative outlooks. Failure to address the debt coverage issues will hamper cost effective financing of plant and equipment.

The average billing rates, including the fuel component, or Energy Rate Component (ERC), under recommended rates are shown in Table 2-2. The combined annual increase ranges from 3.2 percent to 11.3 percent. In 2010, the 7 percent overall increase results in a combined bill increase of only 3.2 percent because the ERC forecast in 2010 is lower than the ERC in 2009. In 2011 the combined bill increases 11.3 percent because the ERC rate is forecast to be higher due to scheduled major outages at BPU's generating stations, which results in additional power purchased at market prices.

Table 2-2
Average Unit Revenue ($/kWh) - Recommended Rates

Description	Fiscal Year Ending December 31, 2010	2011	2012	2013	2014
Base Rates	$ 0.0516	$ 0.0551	$ 0.0590	$ 0.0632	$ 0.0633
ESC	0.0005	0.0013	0.0013	0.0013	0.0013
ERC	0.0243	0.0286	0.0298	0.0326	0.0357
Total Average Billing Rate	$ 0.0764	$ 0.0850	$ 0.0901	$ 0.0970	$ 0.1002
Annual Percentage Increase	3.2%	11.3%	6.0%	7.7%	3.3%

2.1 Study Objectives

The objectives of the rate study are as follows:

1. Forecast the electric utility revenues and revenue requirements for a five-year period FY 2010 – 2014 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 a class cost of service analysis for the utility to identify appropriate revenue levels for each class of service.
3. Recommend revised rates and rate schedules that reflect cost of service considerations and practical rate implementation constraints.

2.2 Utility Financial Operations Under Existing Rates

Black & Veatch uses the cash basis of determining revenue requirements for municipal utilities 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 sales revenues under existing base rates, including Energy Rate Component (ERC) revenues, Borderline, and wholesale sales are forecast to increase from $190.2 million in 2010 to $216.5 million in 2014, representing approximately an average 3.3 percent annual increase in revenues. Of that amount, the revenue forecast to be recovered in base rates increases from $108.5 million in 2010 to $111.5 million, an average annual increase of only 0.7 percent.

2.3 Revenue Requirements

Operation and Maintenance (O&M) expenses in the forecast period are based on the approved 2009 budget and escalated on the following assumptions:

- Only specific approved wage increases in 2010 are included for the Clerical bargaining unit and Steps
- Labor escalation from 2011 – 2014 is 2 percent annually
- Pension liability is increased in 2010 (3 percent) and 2012 (2 percent)
- Labor burden and benefits for regular salary are a percent of direct labor; 57 percent in 2010 and 2011 and 59 percent starting in 2012 through the end of the study period
- Benefits for overtime salary are a percent of overtime labor; 16.25 percent in 2010 and 2011 and 18.25 percent starting in 2012 through the end of the study period
- Non-labor expenses are escalated 4 percent annually
- Labor attrition (open positions in the 2009 Budget) is gradually phased out by 2014. This assumes 2009 budgeted staffing levels will be filled by 2014
- Bad debt expense is increased in proportion to increases in projected rate revenue

Certain items such as scheduled outages and major maintenance at the generating stations, have been added or removed from the O&M forecast based on input from the BPU.

The Capital Improvement Plan (CIP) is based on the FY 2009 budget, 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 for both capital and environmental projects. The environmental bond debt service payment will be funded by a recommended Environmental Surcharge (ESC).

Debt financing a portion of major capital expenditures is recommended to a) reduce rate impact on current customers and b) recover these capital dollars, over time, from the future customers who will benefit from these investments in the Utility System. Revenue bonds are projected to be issued in 2010, 2012, and 2014. The 2010 bonds include proceeds for both capital projects ($35 million) and environmental projects ($40 million). We recommend recovery of the debt service associated with capital projects required for environmental compliance through a recommended Environmental Surcharge (ESC). The amount of projected revenue bonds (including issuance expenses) and the annual debt service payment for the proposed bonds are shown in Table 2-3.

Table 2-3
Proposed Revenue Bonds and Debt Service[1]

Description	Fiscal Year Ending December 31, 2010	2011	2012	2013	2014
Environmental Bond	$ 40,820,000	$ -	$ -	$ -	$ -
Capital Bond	36,220,000	-	107,650,000	-	26,020,000
Total Proposed Bonds at Par	$ 77,040,000	$ -	$ 107,650,000	$ -	$ 26,020,000
Debt Service Payment					
Proposed Bonds	$ 2,118,600	$ 6,115,968	$ 9,076,343	$ 14,141,206	$ 14,856,756

(1) Assume 25 year bond at 5.50% interest, no principal in first year

The BPU collects from customers and transfers revenue to the Unified Government of Wyandotte County (UG) through a Payment in Lieu of Taxes (PILOT) at a rate ranging from 9.9 to 12.8 percent of adjusted gross revenue, less the off system sales fuel revenue. Adjusted gross revenue is equal to total revenue less other (non-operating) revenue.

The BPU currently does not have adequate operating cash reserve funds to maintain liquidity in accordance with stated financial guidelines. The cash operating reserve target should equal the average amount of Operation and Maintenance Expenses (as defined in the Trust Indenture) for any 60-day period in the preceding (12) month period. Based on the financial forecast, the minimum cash Operating Reserve should be approximately $26 million in 2010 and increase to $33 million in 2014. Based on year-to-date data in November 2009, the forecasted electric cash Operating Reserve balance at the end of 2009 is approximately $8.9 million. As a result, a large portion of the recommended base rate increases in this report are required to build the Operating Reserve balance to the stated target by 2014.

2.3.1 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 on an individual basis.

The revenue bond Trust Indenture provides that utility rates shall be maintained such that net revenue during each fiscal year will be equal to not less than 120 percent of the maximum annual debt service in each year on a combined utility basis. For the issuance of parity revenue bonds, net revenue must be equal to not less than 130 percent of the maximum annual debt service in the immediately prior fiscal year and projected future net revenue must be equal to not less than 130 percent of the maximum annual debt service for the period described in the bond Indenture. In accordance with the bond Trust Indenture, net revenue includes PILOT revenue but not PILOT expense.

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 Unified Government. 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 the maximum annual debt service.

2.4 Forecast Deficits Under Existing Rates

Total cash revenue requirements consist of operation and maintenance (O&M) expenses, funding obligations, debt service, capital expenditures, and PILOT transfers to the UG.

Under existing rates, annual revenue deficits will erode the BPU's ability to meet target debt service coverage levels, draw down cash reserve fund balances, and reduce the utility's ability to adequately fund and implement the Capital Improvement Plan (CIP). As shown in Table 2-4, under existing rates, a negative annual operating deficit is forecast beginning in 2009 and increases to a $106.4 million cumulative deficit in 2014.

Projections of debt service coverage under existing rates during the study period for the electric utility, without PILOT revenue, are shown in Table 2-4. As indicated, coverage under existing rates is projected to be less than 1.3 times maximum annual debt service in 2010 and 2011, and less than 1 times maximum annual debt service in 2012 through 2014.

Table 2-4
Annual Surplus / (Deficiency) from Operations and Debt Service Coverage– Existing Rates

	Fiscal Year Ending December 31,				
Description	2010	2011	2012	2013	2014
Carryover from 2009 Budget	$ (3,328,400)				
Annual Surplus / (Deficiency)	(457,500)	(12,617,700)	(20,577,200)	(31,616,200)	(37,818,400)
Cumulative	$ (3,785,900)	$ (16,403,600)	$ (36,980,800)	$ (68,597,000)	$ (106,415,400)
Debt Service Coverage[1]	1.28	1.08	0.77	0.78	0.62

(1) Coverage calculation excludes PILOT revenue

2.5 Recommended Rate Adjustments

Based on the forecast of revenues under existing rates and revenue requirements, the recommended base rate percentage adjustments are:

Table 2-5
Recommended Base Rate Adjustments

	Fiscal Year Ending December 31,				
Description	2010	2011	2012	2013	2014
Base Rates	7.0%	7.0%	7.0%	7.0%	0.0%
ESC	1.0%	1.6%	0.0%	0.0%	0.0%
Date Effective	June 1, 2010	January 1, 2011	January 1, 2012	January 1, 2013	

The recommended minimum base rate adjustments result in annual operating surpluses from 2010 through 2014. Target Operating Reserve levels are not met until 2013 and target debt service requirements are not met until 2014. Under recommended rates and the planned debt financing, debt service coverage excluding revenue from PILOT is forecast to improve from 1.34 in 2009 to the target coverage of 1.60 in 2014, as shown in Table 2-6.

Debt service coverage is calculated as net revenues (gross revenues minus operating expenses) divided by the maximum future debt service payment. As described above, PILOT revenue is excluded from gross revenues before calculating debt service coverage because it is a pass through revenue and the transfer to the government is not included in the operating expenses portion of the calculation. The PILOT adjustment is consistent with the method used by bond rating agencies to rate BPU debt.

Table 2-6
Debt Service Coverage Requirements

Line	Description	2009	2010	2011	2012	2013	2014
	Rate Covenant						
1	Net Revenue including PILOT Revenue	$47,902,300	$66,661,000	$74,496,700	$77,607,900	$89,412,600	$85,981,300
2	Maximum Annual Debt Service Requirements - Total Debt	$22,956,294	$29,072,262	$28,484,619	$36,505,218	$36,505,218	$38,444,992
3	Coverage Ratio	2.09	2.29	2.62	2.13	2.45	2.24
4	Target	1.20					
	Financial Guidelines						
5	Net Revenue including PILOT Revenue	$47,902,300	$66,661,000	$74,496,700	$77,607,900	$89,412,600	$85,981,300
6	Maximum Annual Debt Service Requirements - Total Debt	$22,956,294	$29,072,262	$28,484,619	$36,505,218	$36,505,218	$38,444,992
7	Coverage Ratio	2.09	2.29	2.62	2.13	2.45	2.24
8	Target	1.60					
9	Net Revenue excluding PILOT Revenue	$30,815,100	$42,647,900	$49,476,100	$55,622,300	$65,581,200	$61,370,300
10	Maximum Annual Debt Service Requirements - Total Debt	$22,956,294	$29,072,262	$28,484,619	$36,505,218	$36,505,218	$38,444,992
11	Coverage Ratio	1.34	1.47	1.74	1.52	1.80	1.60
12	Target	1.60					

2.6 Utility Operations Under Recommended Rates

The summary forecast of annual operating surpluses under recommended rates are presented in Table 2-7. The recommended rates result in annual surpluses through 2013. These surpluses are used to gradually build up the operating reserve to meet stated targets by the end of the study period. Total debt service coverage under recommended rates ranges from 1.47 to 1.80, without PILOT revenue, as shown in Table 2-8.

Table 2-7
Annual Surplus / (Deficiency) from Operations - Recommended Rates

	Fiscal Year Ending December 31,				
Description	2010	2011	2012	2013	2014
Ending 2009 Cash Balance	$ 8,856,400				
Annual Surplus / (Deficiency)	5,099,700	$ 6,023,400	$ 6,889,400	$ 5,556,500	$ (247,300)
Total	$ 13,956,100	$ 6,023,400	$ 6,889,400	$ 5,556,500	$ (247,300)
Cumulative Cash Balance	$ 13,956,100	$ 19,979,500	$ 26,868,900	$ 32,425,400	$ 32,178,100

Table 2-8
Debt Service Coverage Under Existing and Recommended Rates[1]

	Fiscal Year Ending December 31,				
Description	2010	2011	2012	2013	2014
Existing Rates	1.28	1.08	0.77	0.78	0.62
Recommended Rates	1.47	1.74	1.52	1.80	1.60

(1) Debt service coverage calculated without PILOT revenue

2.7 Cost of Service

The Black & Veatch cost of service model is a two-dimensional cost matrix that allocates BPU total cost of service to each rate class. The resultant class cost of service requirements are divided by the class billing units to develop unbundled units of cost of service, 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 and equitable rates.
- Test year revenue requirements are reduced by ERC 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 $116.1 million (Tables 2-9 and 4-1) includes the recommended 7 percent base rate increase for the test year 2010. Because the 2010 recommended rate increase will only be recovered over 7 months, a margin adjustment equal to 5 months of rate increases that will not be realized has been included in the cost of service for rate design purposes.
- In performing the cost analysis, net cost of service is first functionally classified into production, transmission, distribution, and customer related service classifications. These classifications are further classified into capacity or demand, energy, customer, and direct assigned cost components. Capacity, energy and customer allocation factors are developed to assign the cost responsibility for each component to each service 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. These 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 and metered energy use.
- Table 2-9 shows the results of the cost of service analysis by class. The required percent changes by class to cover costs for the class assuming each class produces uniform cost recovery range from -8.3 percent to 26.5 percent.

Table 2-9
Cost of Service Summary by Rate Class – 2010 Test Year

		[A]	[B]	[C]	[D]	[E]	[F]
		2010				Base Difference	
Line	Description	Retail Sales	Base Revenue Existing Rates	Base Net COS	Base COS Adjustment	Amount	Percent
		MWh				[C] + [D] - [B]	[E] / [B]
	TOTAL COST OF SERVICE						
1	Rate 100 - Residential	525,174	$ 33,582,542	$ 36,932,280	$ 1,891,405	$ 5,241,143	15.6%
2	Rate 200 - Small General Service	210,426	15,894,606	14,502,956	753,552	(638,098)	-4.0%
3	Rate 300 - Large General Service	659,877	33,504,839	29,234,973	2,126,707	(2,143,159)	-6.4%
4	Rate 400 - Large Power Service	796,030	20,771,681	23,878,657	2,399,809	5,506,785	26.5%
5	Rate 500 - School District	51,320	3,282,409	2,863,355	173,978	(245,076)	-7.5%
6	Rate 700 - Lighting	8,320	1,493,910	1,328,747	40,784	(124,379)	-8.3%
7	Borderline		433,029	900,335	(467,306) (1)	-	
8	KCK		-	4,903,701	(4,903,701) (1)	-	
9	BPU Interdepartmental		-	1,582,199	(1,582,199) (2)	-	
10	Total	$ 2,251,148	$ 108,963,016	$ 116,127,203	$ 433,029	$ 7,597,216	7.0%

(1) Allocated to Paying Classes on basis of Retail Sales, Column [A]
(2) Allocated to Paying Classes on basis of Base Net COS, Column [B]

2.8 Rate Design

In practice, rates must be redesigned 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 A provides a revised Rate Application Manual, including the recommended rates. Recommended changes to the Rate Application Manual include the following:

- Adding new definitions for billing cycle, customer and term of contract
- Modifying definitions for customer charge to customer access charge, demand and demand charge, energy rate component, summer and winter base rate periods. Summer is defined as the four months May through August. Winter is the remaining eight months. For cycle billed customers, the summer bills are bills rendered for four cycles after May 15
- In each rate schedule replacing the term customer charge with customer access charge to more clearly define the nature of the cost
- Modifying the minimum bill provision to include the customer access charge, facilities demand and other applicable demand charges
- Establishing a minimum usage requirement for installation of a demand meter for the Small General Service rate
- Modifying the definition of billing demand to reflect seasonal and time of use provisions where applicable
- Changing the Metering credit provisions in the tariffs from a billed revenue adjustment to a metered kW and kWh adjustment
- Adding a term of contract provision to general service rate schedules
- Eliminating the ERC provision related to service voltage consistent with the metering credit provisions
- Adjusting the ERC Purchase Power definition to include all generation and transmission capacity charges that may be assessed by the Southwest Power Pool related to transmission market operations including energy imbalance, day-ahead energy, capacity and ancillary service markets.
- Increasing the frequency of the ERC adjustment to a quarterly adjustment with reconciliation adjustments to occur 90 days after the close of the quarter to track fuel costs to rates more closely

- Adding an Electric Heating rate for the Residential rate class
- Adding an Environmental Surcharge rider
- Removing the Economic Development Rider from the Rate Manual. Economic development activities will be based on future policy direction
- Adding a Medium General Service rate class, and dividing the existing Large General Service rate class into two classes to track costs better

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

With respect to individual rates, the changes applicable to the first year rates have focused on recovery of fixed costs in fixed charges to the extent practicable and to introducing improved seasonal billing provisions. Based on a statistical analysis of hourly costs, the optimal summer season includes the months of May through August. Using these months' results in the largest seasonal difference in cost and the smallest cost differences during the season. The recommended rates all include seasonal energy charges.

The rate process began with a review of the class cost of service results. For classes with indicated cost of service increases larger than the system average, a larger percentage increase has been proposed. As a general rule, no class will receive an annual rate increase greater than 50% above the system average rate increase. For classes recovering more than the indicated cost of service, either a lower than average increase, or no increase has been proposed.

2.8.1 Residential Rate Class – Rate 100

The residential 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 of 7 percent per year in the next three years and at the system average in the fourth year. The proposed changes to the residential base rate design reflect the proposed first year revenue increase target of 8.75 percent (Table 2-12). The rate redesign includes the replacement of the customer charge with a Customer Access Charge. The Customer Access Charge is designed to cover the costs incurred to allow the customer to access and use power from the system. This change is designed to more accurately reflect the costs that customers pay for access to the system. Although this charge does not cover all of the costs of access, the rate is designed to move toward full recovery of access costs in the rate. The proposed charge is $12.25 per month. At this level, the charge represents about 55 percent of the cost of access.

With respect to changes to the Customer Access Charge, one concern is always 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 LIEAP 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 Access Charge, the lesser the impact on the kWh charges in the rate. As customers use power above the average the increase is proportionally lower. Third, the impact of the increase in the Customer Access Charge is less than 19 cents per day.

The energy charge portion of the residential rate consists of three seasonally differentiated energy blocks. We have retained the existing structure for rate continuity.

An additional Residential rate has been recommended for customers with electric heating facilities. The new Residential Electric Heating rate (Rate 101) has the same summer blocks as Rate 100, but has declining blocks in the winter months to promote use of electric heating.

Table 2-10
Present and Recommended Residential Energy Charges

Rate Blocks	Current Charge	2010 Recommended Charge	Percent Change
Rate 100 – Residential			
Summer	$/kWh	$/kWh	
First 1000 kWh	$0.0563	$0.0600	6.6 %
Next 1000 kWh	$0.0672	$0.0700	4.2 %
All Additional kWh	$0.0992	$0.0900	-9.3 %
Winter			
First 1000 kWh	$0.0563	$0.0475	-15.6 %
Next 1000 kWh	$0.0266	$0.0450	69.2 %
All Additional kWh	$0.0266	$0.0450	69.2 %
Rate 101 – Residential Electric Heating			
Summer	$/kWh	$/kWh	
First 1000 kWh	$0.0563	$0.0600	6.6 %
Next 1000 kWh	$0.0672	$0.0700	4.2 %
All Additional kWh	$0.0992	$0.0900	-9.3 %
Winter			
First 1000 kWh	$0.0563	$0.0475	-15.6 %
Next 1000 kWh	$0.0266	$0.0300	12.8 %
All Additional kWh	$0.0266	$0.0266	0.0 %

The following Table 2-11 shows the impact on monthly residential bills in 2010 using the median usage from 2008 for a winter month (January) and a summer month (August). Monthly bills are calculated including ERC and ESC charges to show the overall impact on customers' bills.

Table 2-11
Impact on Monthly Residential Bills

	Class Median Monthly Usage(1)	Monthly Bill (2) Existing Rates	Monthly Bill (2) 2010 Recommended Rates	Change in Monthly Bill Under Recommended Rates	Percentage Increase
	kWh	$	$	$	
100 - Residential					
Winter	625	$57.04	$57.50	$0.46	0.8%
Summer	1,150	$101.04	$111.12	$10.08	10.0%
101 - Residential Electric Heating					
Winter	2,300	$153.59	$154.99	$1.40	0.9%
Summer	1,200	$105.62	$116.13	$10.51	10.0%

Total Residential Revenue Under Existing Rates	$46,395,140.10
Total Residential Revenue Under Recommended Rates	$49,599,489.51
Recommended First Year Revenue Increase (3)	$3,204,349.41
Total Number of Bills	724,704
Average Increase per Bill per Month	$4.42

Notes:
(1) Median usage for January 2008 and August 2008
(2) Monthly bill calculations include ERC Rider and ESC Rider, but no PILOT or taxes
(3) Revenue increase if rate was in effect for all of 2010

2.8.2 Small General Service Class – Rate 200

The Small General Service Class cost of service indicates a small over recovery. As a result, we have proposed a lower than system average percentage increase for the first three years and a system average increase in the fourth year. The first year increase target is 5.06 percent (Table 2-12). The customer charge has been replaced by a Customer Access Charge set at about 55 percent of the customer costs. The Customer Access Charge is $25.00 per month.

The facilities demand charge and the base demand charge have been increased to reflect cost of service principles. The energy charge blocks remain the same with an increase in the summer first block and a decrease in the winter first block to recognize the seasonal differences in costs. The second block of the rate increases in both the summer and winter seasons, but maintains a seasonal differential to more closely approximate the marginal cost by season.

For customers without a demand meter the rate is a flat, seasonally differentiated energy charge with a higher summer rate and a lower winter rate. The rate differential is based on the seasonal cost differences.

2.8.3 Medium General Service Class – Rate 2500

A Medium General Service Class has been added as a new rate class and has effectively divided the existing Large General Service Class into two classes. The existing Large General Service rate is available to customers having a demand between 70 kW and 4,000 kW. The new Medium General Service Class will be for customers with demands between 70 kW and 1,000 kW. The cost of service basis for this class is the existing Large General Service Class, which indicates an over recovery in cost of service. As a result, we have proposed a lower than system average percentage increase for the first three years and a system average increase in the fourth year. The first year increase target is 5.06 percent (Table 2-12).

2.8.4 Large General Service Class – Rate 300

The revised Large General Service class is available to customers with demands greater than 1,000 kW, but below 4,000 kW. Rate design guidelines for the new Large General Service Class are based on the existing class cost of service. The existing Large General Service Class cost of service indicates an over recovery in cost of service. As a result, we have proposed a lower than system average percentage increase for the first three years and a system average increase in the fourth year. The first year increase target is 5.06 percent (Table 2-12). The customer charge has been replaced with a Customer Access Charge. The Customer Access Charge has been increased to 45 percent of the customer costs. This percentage was based on the fact that the facilities demand charge has been increased as well. Thus the combined charges recover more of the fixed costs in fixed charges.

The increase in the facilities demand charge and the base demand charge are based on cost of service principles and recover the remainder of the allocated rate increase. The energy charges in this schedule now reflect a seasonal differential in the first block and the second block remains the same.

2.8.5 Large Power Service Class – Rate 400

The Large Power Service Class cost of service indicates under recovery of cost of service. As a result, we have proposed a higher than system average percentage increase for the first three years and a system average increase in the fourth year. The first year increase target is 10.4 percent (Table 2-12). The increase is based on the fact that this class of service exhibited the largest percentage increase to achieve cost of service and thus warranted the largest percentage increase.

The increases for this schedule include an increase to the Customer Access Charge, the facilities demand charge and the base demand charge. The proposed energy charges also reflect a seasonal differential, with the summer energy charges remaining the same and the winter energy charges reduced slightly. The facilities charge changes are based on the cost of service with the secondary service charge increasing, the primary service charge decreasing slightly and the substation charge increasing. The base demand charge increased to produce the target revenue.

2.8.6 Unified School District #500 and Lighting Classes - Rate 700

Both of these classes produce revenues in excess of cost of service. We propose no increase for these two classes in the first year. As shown in Table 2-12, in subsequent years we propose a less than average increase in the second and third year and an average increase in the fourth year.

2.8.7 Metering Adjustment Clauses

In designing Rates 200-500 we have revised the metering adjustment clause to adjust the measured kW and kWh volumes. The existing rates adjusted the total bill, including the ERC and customer charges. We recommend the ERC be applied to the adjusted measured kWh. As such the Service Voltage factors in the existing ERC rider are no longer needed. We have revised the recommended ERC rider accordingly.

2.8.8 Subsequent Year Increases

The following table provides the recommended base rate increase for each rate class. The overall average increase is 7 percent per year.

Table 2-12
Recommended Rate Class Percentage Increases by Year

Base Rate Summary	2010	2011	2012	2013
Rate 100 – Residential	8.75%	8.75%	8.00%	7.00%
Rate 200 - Small General Service	5.06%	6.00%	6.00%	7.00%
Rate 2500 – Medium General Service	5.06%	5.00%	6.00%	7.00%
Rate 300 - Large General Service	5.06%	5.00%	6.00%	7.00%
Rate 400 - Large Power Service	10.40%	8.75%	8.00%	7.00%
Rate 500 - USD #500	0.00%	3.00%	5.00%	7.00%
Rate 700 – Lighting	0.00%	3.00%	5.00%	7.00%

As the table illustrates, the increases are designed to move the various rate classes toward cost of service over time while avoiding disruptively large increase relative to the average 7 percent increase. In the last year, each class is increased by the average to allow for the system to develop a new cost study at that time to assess the relative returns and the need for further rate adjustments. We propose that there be no rate design change in these years. Rather, the rate increase will be implemented as a percentage surcharge applicable to the base rate bill. The applicable annual surcharges by rate class for 2011 through 2013 are shown in Table 2-13.

Table 2-13
Applied Percentage Surcharges by Year

Base Rate Summary	2011	2012	2013
Rate 100 – Residential	8.75%	17.45%	25.67%
Rate 200 - Small General Service	6.00%	12.36%	20.23%
Rate 2500 - Medium General Service	5.00%	11.30%	19.09%
Rate 300 - Large General Service	5.00%	11.30%	19.09%
Rate 400 - Large Power Service	8.75%	17.45%	25.67%
Rate 500 – USD #500	3.00%	8.15%	15.72%
Rate 700 – Lighting	3.00%	8.15%	15.72%

2.8.9 Energy Rate Component (ERC)

We are recommending several changes in the Energy Rate Component (ERC) to improve the timely recovery of costs. These include:

- Increasing the frequency of the ERC adjustment to a quarterly adjustment with reconciliation adjustments to occur 90 days after the close of the quarter.
- Eliminating the ERC provision related to service voltage adjustment consistent with the metering credit provisions in the recommended base rates.
- Adjusting the Purchase Power definition to include all generation and transmission capacity charges. Additional charges that may be assessed by the Southwest Power Pool and related to transmission, market operations including energy imbalance, day-ahead energy, capacity and ancillary service markets.

2.8.10 Environmental Surcharge (ESC)

We are recommending a new Rider, an Environmental Surcharge (ESC). The purpose of this Rider is to provide for the recovery of the Utility's capital investment in projects not recovered in base rates that are required to meet Federal, state, reliability council, or local environmental regulations. Several future capital intensive projects are being considered by the BPU should the anticipated environmental regulations be mandated. The capital costs of these projects are not included in the recommended base rates, but are recovered through the recommended Environmental Surcharge.

The ESC will be applicable to all electricity billed to retail customers excluding sales to the Board of Public Utilities (BPU), the portion of Unified Government of Wyandotte County/Kansas City, Kansas belonging to customer class "City of KCK" and contract customers where recovery of a surcharge is not permitted under the terms of a contract. The surcharge is intended to recover only the annual cash expenditures of the Utility, whether in direct expenditures or in the form of debt service payments for Environmental Bonds, until such time costs can be recovered in base rates.

The calculation of the projected ESC shall be made in the fourth quarter of each calendar year and applied to customer bills rendered beginning January 1 of the following calendar year. Based on the current forecast the initial application of the ESC will begin in July 2010, following the issuance of Environmental Bonds. The Utility shall provide annual reports to the Board of its collections including a calculation of the total revenue collected under this Rider.

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 Utility for any dollar amount expended on required environmental capital projects for retail customers. The Environmental Surcharge is expressed in $ per kWh and rounded to the nearest $0.0001. The forecast 2010 surcharge is $0.0005/ kWh applied to all metered usage. The ESC is presented in Appendix A and includes an annual reconciliation adjustment (true up).

2.9 Other Rate Design Considerations

The BPU is also evaluating the possibility of a Time of Use rate structure and Interruptible and/or Curtailable Service arrangements. Specific rates or riders will not be a part of this rate study, but may be considered on a trial basis, subject to a determination of what is in the best interests of the utility.

2.10 Report Layout

The remainder of this report presents the detailed analyses supporting the information presented in the Executive Summary. In some instances, such as the detailed development of cost of service allocators, the level of detail is too great to present in a report format and is shown in detail in the accompanying Cost of Service and Rate Design Model (Model). The following sections include details of the BPU's Revenues and Revenue Requirements (Section 3.0), Cost of Service Analysis (Section 4.0), and Rate Design (Section 5.0). Appendix A presents a revised Rate Manual based on changes recommended in this report.

3.0 REVENUES AND REVENUE REQUIREMENTS

The electric utility of the BPU provides service to residential, commercial, industrial, schools, private lighting, municipal, and wholesale customers. The electric utility currently serves approximately 65,000 retail customers with projected rate revenues under existing rates for FY 2010 of $163.1 million. Total retail energy sales are forecast to be 2.25 million megawatt hours (MWh). This section summarizes our forecast of electric utility revenue and revenue requirements of the BPU for the period 2010 through 2014.

Overall adequacy of existing rates is tested by comparing revenues under existing rates with forecast revenue requirements, as presented in Table 3-3. To test the reasonableness of cost recovery by customer class rate schedules, electric utility revenue requirements are allocated to cost functions and to customer classes and compared to class revenues. The cost of service analysis for the utility is presented in section 4.1.

3.1 Financial Operations Under Existing Rates

The base 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 2008 actual billing determinants. The load forecast used (2009 Load Forecast) was prepared by BPU and Black & Veatch in November 2009 and based on the forecast that was developed in 2008 for the 2009 budget process and updated to reflect year-to-date actual sales for 2009. The new forecast was also used for the BPU 2010 budget process. For the 2009 forecast, developed in fourth quarter 2009, the SmartForecasts™ forecasting software was used to analyze historic trends and project future demand based on the historic trends and future projections for population shifts, commercial growth, and industrial load trends. The 2009 actual retail sales numbers were lower than what had been forecast in late 2008, so that information was used to adjust future load projections. Energy efficiency programs are expected to hold loads from a snap rebound from the recent recession.

Total retail loads for the balance of 2009 were forecast and added to actual year to date retail sales to estimate year ending 2009 total retail sales of about 2,138 GWh. Total retail sales for 2010 are expected to be about 5¼ percent higher than 2009 or about 2,250 GWh. With the implementation of energy efficiency programs, the 2011 total retail sales are expected to be approximately level with the 2010 total retail sales. Subsequent to 2011, annual energy growth is expected to return to historic trends of about 1 percent annual growth and be similar to pre-2009 years, so 2012-2014 forecasted loads were based on the growth rates determined using the SmartForecasts™ forecasting software.

The forecast of electric sales is based on the 2009 Load Forecast prepared by BPU and Black & Veatch. The detailed billing determinants by rate code were derived by first translating the 2009 load forecast from customer classes (residential, commercial, industrial, etc.) to rate classes (100, 200, 300, 400, etc.). Once the load forecast was expressed in rate classes, the annual percentage increase in kilowatt hours (kWh) by rate was applied to the actual 2008 billing determinants, resulting in a detailed projection of sales that ties to the 2009 Load Forecast. The level of detail in the billing determinants was generally the same as maintained by BPU, meaning there are generally four rate IDs for each rate class, based on whether the customer receives primary or secondary service and is primary or secondary metered. We have expanded this detail for all customers receiving EDR rider or EDD discounts. 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

		[A]	[B]	[C]	[D]	[E]	[F]
		For the Fiscal Year Ended:					
Line	Description	2009	2010	2011	2012	2013	2014
1	**Energy Sales Growth Forecast**[1]						
2	Rate 100 - Residential	-8.6%	4.3%	-0.8%	0.6%	0.6%	0.7%
3	Rate 200 - Small General Service	3.8%	4.6%	-0.3%	0.4%	0.7%	0.8%
4	Rate 300 - Large General Service	0.6%	5.9%	0.9%	0.5%	1.2%	1.3%
5	Rate 400 - Large Power Service	-9.1%	5.0%	0.5%	0.5%	1.0%	1.1%
6	Rate 500 - School District	-7.2%	14.9%	-4.9%	1.4%	0.0%	0.1%
7	Rate 700 - Lighting	-8.2%	7.8%	-2.5%	0.7%	0.2%	0.3%
8	KCK Use	-45.1%	-2.4%	-1.1%	0.0%	0.5%	0.7%
9	KCK Unmetered	-28.9%	-2.4%	-1.1%	0.0%	0.5%	0.7%
10	BPU Interdepartmental	-29.0%	-2.4%	-1.1%	0.0%	0.5%	0.7%
11	Borderline	-28.3%	38.7%	2.4%	2.1%	1.5%	1.2%
12	Nearman Participant	9.1%	0.0%	0.0%	0.0%	0.0%	0.0%
13	Off-system Sales	-33.9%	-0.5%	0.5%	-1.8%	0.9%	1.4%

(1) Escalation from 2008 Actuals

Table 3-2
Forecast of Annual Electric Sales (MWh)

Line No.	Description	2009	2010	2011	2012	2013	2014
	Forecast Retail Sales (MWh)						
1	Rate 100 - Residential	503,500	525,200	521,100	524,300	527,700	531,500
2	Rate 200 - Small General Service	201,100	210,400	209,800	210,600	211,900	213,600
3	Rate 300 - Large General Service	623,300	659,900	665,800	669,100	676,900	685,900
4	Rate 400 - Large Power Service	758,200	796,000	799,900	803,600	811,600	820,600
5	Rate 500 - School District	44,700	51,300	48,800	49,500	49,500	49,600
6	Rate 700 - Lighting	7,700	8,300	8,100	8,200	8,200	8,200
7	Total Retail	2,138,500	2,251,100	2,253,500	2,265,300	2,285,800	2,309,400
8	KCK Use	24,000	23,400	23,100	23,100	23,200	23,400
9	KCK Unmetered	26,600	26,000	25,700	25,700	25,800	26,000
10	BPU Interdepartmental	32,600	31,800	31,500	31,500	31,600	31,900
11	Borderline	13,300	18,400	18,800	19,200	19,500	19,800
12	Wholesale MWh	655,400	654,400	655,400	651,400	653,400	656,400
13	Total MWh (no losses)	2,890,400	3,005,100	3,008,000	3,016,200	3,039,300	3,066,900

Revenue related to recovery of retail fuel, purchased power, and ancillary charges are recovered with the Energy Rate Component (ERC) rider. The 2009 Load Forecast provides the generation requirements for the production cost model (ProSym™), which is used to create a 6 year ERC Forecast, which forecasts fuel, purchased power, and capacity expenses, wholesale revenue, and retail ERC through 2014. While the ERC rider adjusts seasonally, for the purposes of this report, a single annual ERC rate is used and annual ERC and wholesale revenue 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 study to be on the base rate revenue.

Revenues under existing rates reflect the two current sources of revenue: base rate revenue and fuel revenue, where base rates are the existing rates that have been in effect since January 1, 2007. The forecast of operating revenues under existing rates are shown in Table 3-3. Line 14 shows the combined base and fuel revenue and ranges from $190.2 million in 2010 to $216.5 million in 2014. Other revenue from operating and non-operating sources is shown on line 26 and ranges from $29.8 million in 2010 to $28.7 million in 2014.

Total revenue under existing rates is summarized on line 27 of Table 3-3 and ranges from $220.0 million in 2010 to $245.2 million in 2014.

Table 3-3
Projected Operating Results Under Existing Rates
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Line	Description	Year 2009	2010	2011	2012	2013	2014
1	Retail Sales (MWh)	2,138,519	2,251,148	2,253,570	2,265,277	2,285,834	2,309,313
	REVENUES ($)						
2	**Base:**						
3	Retail Base Revenue	103,049,800	108,530,000	108,429,500	109,065,400	110,190,300	111,524,800
4	Borderline	270,900	433,000	380,000	380,500	304,600	290,100
5	Nearman Participants	7,036,600	8,776,900	8,751,400	8,494,300	7,872,500	7,735,300
6	Off System Sales	568,800	3,560,800	2,558,300	2,683,400	2,339,700	1,100,000
7	**Total Base Revenue**	110,926,100	121,300,700	120,119,200	120,623,600	120,707,100	120,650,200
8	**Fuel:**						
9	Retail ERC Revenue	55,156,000	54,625,700	64,500,400	67,498,900	74,473,900	82,385,300
10	Borderline Fuel Revenue	268,300	315,100	385,900	401,800	489,200	513,300
11	Nearman Participants Fuel Revenue	6,247,700	5,803,600	6,610,700	6,085,900	7,878,600	7,475,800
12	Off System Sales Fuel Revenue	5,399,400	8,154,100	7,621,500	8,897,000	8,445,400	5,496,300
13	**Total Fuel Revenue**	67,071,400	68,898,500	79,118,500	82,883,600	91,287,100	95,870,700
14	**Total Rate Revenue**	**177,997,500**	**190,199,200**	**199,237,700**	**203,507,200**	**211,994,200**	**216,520,900**
15	**Other Revenue:**						
16	PILOT Rate	9.90%	12.80%	11.90%	9.90%	9.90%	9.90%
17	PILOT	17,087,200	23,301,800	22,802,300	19,266,400	20,151,300	20,891,400
18	Forfeited Discounts	2,142,000	2,184,800	2,228,500	2,273,100	2,318,600	2,365,000
19	Connect/Disconnect Fees	1,020,000	1,040,400	1,061,200	1,082,400	1,104,000	1,126,100
20	Tower/Pole Attachment Rentals	959,000	1,007,000	1,027,100	1,047,600	1,068,600	1,090,000
21	Ash Disposal	153,000	156,100	159,200	162,400	165,600	168,900
22	Diversion Fines	61,200	62,400	63,600	64,900	66,200	67,500
23	Service Fees	1,224,000	1,248,500	1,273,500	1,299,000	1,325,000	1,351,500
24	Other Miscellaneous Revenues	142,000	144,800	147,700	150,700	153,700	156,800
25	Investment Income	1,256,000	669,300	929,500	1,242,300	1,415,500	1,468,100
26	**Total Other Revenue**	**24,044,400**	**29,815,100**	**29,692,600**	**26,588,800**	**27,768,500**	**28,685,300**
27	**Total Revenue**	**202,041,900**	**220,014,300**	**228,930,300**	**230,096,000**	**239,762,700**	**245,206,200**
28	**REVENUE REQUIREMENTS ($)**						
29	**Fuel Expense**						
30	Retail						
31	Generation Fuel Costs	33,565,500	33,237,000	40,485,000	39,874,700	50,164,900	48,191,000
32	Purchased Power	21,590,500	21,388,700	24,015,400	27,624,200	24,309,000	34,194,300
33	Total Retail Fuel	55,156,000	54,625,700	64,500,400	67,498,900	74,473,900	82,385,300
34	Borderline Fuel Costs	268,300	315,100	385,900	401,800	489,200	513,300
35	Nearman Participants Fuel Cost	6,247,700	5,803,600	6,610,700	6,085,900	7,878,600	7,475,800
36	Off System Fuel Costs	5,399,400	8,154,100	7,621,500	8,897,000	8,445,400	5,496,300
37	**Total Fuel Expense**	67,071,400	68,898,500	79,118,500	82,883,600	91,287,100	95,870,700

Table 3-3
Projected Operating Results Under Existing Rates
Page 2 of 2

Line	Description	Year 2009	2010	2011	2012	2013	2014
38	**Operation and Maintenance Expense**						
39	Non-ERC Capacity Purchases	1,764,100	718,800	-	-	-	-
40	Production	38,777,700	41,763,100	46,015,800	47,290,300	45,370,700	48,059,200
41	Transmission	2,444,300	2,537,200	2,654,500	2,795,800	2,922,400	3,053,400
42	Distribution	20,110,700	20,713,800	21,578,400	22,690,900	23,622,300	24,584,200
43	Customer Accounts	5,503,300	5,768,400	5,961,300	6,191,700	6,380,600	6,512,100
44	Sales	481,500	499,400	514,200	533,000	548,900	565,300
45	Administrative and General	17,986,600	18,722,600	19,450,300	20,288,600	21,070,900	21,870,700
46	**Total O&M Expense**	87,068,200	90,723,300	96,174,500	99,790,300	99,915,800	104,644,900
47	**Total Expenses**	154,139,600	159,621,800	175,293,000	182,673,900	191,202,900	200,515,600
48	**Net Revenues**	47,902,300	60,392,500	53,637,300	47,422,100	48,559,800	44,690,600
49	**Debt Service**						
50	Existing Debt Service	20,644,000	22,956,300	22,368,700	22,345,700	22,361,700	22,364,000
51	2010 Capital Bonds ($36.2 million)	-	996,100	2,700,200	2,700,200	2,700,200	2,700,200
52	2010 Environmental Bonds ($40.8 million)	-	1,122,600	3,415,800	3,415,800	3,415,800	3,415,800
53	2012 Capital Bonds ($107.7 million)	-	-	-	2,960,400	8,025,200	8,025,200
55	2014 Capital Bonds ($26 million)	-	-	-	-	-	715,600
56	**Total Debt Service**	20,644,000	25,075,000	28,484,700	31,422,100	36,502,900	37,220,800
57	Revenue After Debt Service Obligation	27,258,300	35,317,500	25,152,600	16,000,000	12,056,900	7,469,800
58	**Debt Service Coverage Under Existing Rates**						
59	**PILOT revenue included in coverage**						
60	Parity Debt	2.20	2.17	1.97	1.34	1.38	1.20
61	Total System Achieved (Total Debt)	**2.09**	**2.08**	**1.88**	**1.30**	**1.33**	**1.16**
62	Target Minimum Coverage	1.60	1.60	1.60	1.60	1.60	1.60
63	**Without PILOT revenue**						
64	Parity Debt	1.42	1.33	1.13	0.80	0.81	0.64
65	Total System Achieved (Total Debt)	**1.34**	**1.28**	**1.08**	**0.77**	**0.78**	**0.62**
66	Target Minimum Coverage	1.60	1.60	1.60	1.60	1.60	1.60
67	**Other Expenditures and Transfers**						
68	PILOT	17,087,200	23,301,800	22,802,300	19,266,400	20,151,300	20,891,400
69	Cash Financed Capital Projects	11,524,100	11,955,600	14,459,800	17,041,600	23,336,600	24,211,600
70	Less: Reimbursable Projects	(786,400)	(714,400)	(734,700)	(755,700)	(764,700)	(764,700)
71	Capital Lease Payments	368,900	282,100	293,000	75,000	-	-
72	Heat Pump Program	449,900	449,900	449,900	449,900	449,900	449,900
73	Economic Development Fund Authorization	500,000	500,000	500,000	500,000	500,000	500,000
74	**Total Other Exp. And Transfers**	**29,143,700**	**35,775,000**	**37,770,300**	**36,577,200**	**43,673,100**	**45,288,200**
75	Cash Balance Adjustment	1,443,000					
76	**Total Revenue Requirement**	205,370,300	220,471,800	241,548,000	250,673,200	271,378,900	283,024,600
77	**Net Revenue Requirement**	181,325,900	190,656,700	211,855,400	224,084,400	243,610,400	254,339,300
78	Revenue Surplus / (Deficiency) Under Existing	(3,328,400)	(457,500)	(12,617,700)	(20,577,200)	(31,616,200)	(37,818,400)
79	Cumulative Revenue Surplus / (Deficiency)	(3,328,400)	(3,785,900)	(16,403,600)	(36,980,800)	(68,597,000)	(106,415,400)

3.2 Revenue Requirements

The overall adequacy of the existing rates is tested by comparing revenues under existing rates with revenue requirements. Revenue requirements are developed on a cash basis and consist primarily of fuel expenditures, operation and maintenance (O&M) expenses, debt service requirements, transfer to the City, reserve fund requirements, cash financed capital projects, and other non-operating expenses. The forecast of annual revenue requirements is shown in Table 3-3 and discussed in the following sections.

3.2.1 Fuel Expenses

As discussed in Section 3.1, the forecast of fuel expenses for retail, Borderline, and wholesale customers is based on the ERC Forecast resulting from a ProSym run that is tied to the 2009 Load Forecast. The forecast of fuel expenses is summarized on lines 29 through 37 of Table 3-3. 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 expense are set equal to retail fuel expense each year with no consideration of a seasonal true up. The recommended changes to the ERC rider include moving to a quarterly adjustment period and the recovery of fixed capacity charges through the ERC and not in base rates as they are currently recovered. It is assumed this change will take effect in July 2010 and the capacity charges for 2010 have been prorated.

3.2.2 Operation and Maintenance Expense

Operation and Maintenance (O&M) expenses in the forecast period are based on the 2009 approved budget and escalated on the following assumptions:

- Only specific approved wage increases in 2010 are included for the Clerical bargaining unit and Steps
- Labor escalation from 2011 – 2014 is 2 percent annually
- Pension liability is increased in 2010 (3 percent) and 2012 (2 percent)
- Labor burden and benefits for regular salary are a percent of direct labor; 57 percent in 2010 and 2011 and 59 percent starting in 2012 through the end of the study period
- Benefits for overtime salary are a percent of overtime labor; 16.25 percent in 2010 and 2011 and 18.25 percent starting in 2012 through the end of the study period
- Non-labor expenses are escalated 4 percent annually
- Labor attrition (open positions in the 2009 Budget) is gradually phased out by 2014. This assumes 2009 budgeted staffing levels will be filled by 2014
- Bad debt expense is increased in proportion to increases in projected rate revenue

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 input from the BPU.

O&M expenses are summarized on lines 38 through 46 of Table 3-3.

3.2.3 Capital Improvement Plan

The baseline Capital Improvement Plan (CIP) is the 2009 Budget, which provides a six-year (2009 through 2014) capital plan. The primary and preferred source of funds to finance the electric utility CIP is with annual operating revenues. Because surplus operating revenues are not sufficient to finance the entire CIP, bonds are used to provide financing for the projects.

The detailed CIP is shown in Table 3-4. Electric Operations projects are shown on lines 1 through 14. Electric Production projects are shown on lines 15 through 25, plus mandated environmental projects on 27 and 28. Projects common to both the Electric and Water Utilities are shown on lines 30 through 35. The amounts shown for those common projects represent 80 percent of the project costs. The remaining 20 percent is assigned to the Water utility. Major Electric Operations projects over the 6-year period from 2009 through 2014 include $56 million for overhead and underground distribution improvements, $33 million in transmission investment, and $42 million in substation projects. Major Electric Production projects include $20 million in projects at the Nearman Power Complex, $35 million of investment at the Quindaro Power Complex, and the planned construction of a new combustion turbine generator at the Nearman Power Complex (CT5) for $74.5 million.

Mandated environmental projects are shown separately on lines 27 and 28 and include the addition of low-NOx burners and over fire air at both the Nearman 1 and Quindaro 2 steam turbine units. These projects total $40 million and we recommended recovery of these capital costs through a new rider specifically for mandated environmental projects. This Environmental Surcharge (ESC) rider is designed to recover the capital cost portion of mandated projects on a $/kWh basis. The annual ESC rate will be determined by dividing the annual debt service payment, plus recovery of cash financed environmental projects, less contribution from Nearman Participants (wholesale customers), divided by the forecast retail sales for the year, plus or minus an annual true-up for any over- or under- recovery from the prior year. The ESC will also be applied to all future mandated environmental projects.

Table 3-4
Capital Improvement Plan

Line	Description	Year 2009	2010	2011	2012	2013	2014	Total
	Electric System Capital Projects							
1	Electric Unit Equipment	$ 377,000	$ 500,000	$ 4,400,000	$ 4,400,000	$ 4,400,000	$ 4,900,000	$ 18,977,000
2	Electric Ops General Construction	812,136	970,000	890,000	740,000	740,000	640,000	4,792,136
3	Electric Supply General Construction							-
4	Electric Accident Claims	108,200	108,200	108,200	108,200	108,200	108,200	649,200
5	Electric Overhead Distribution	2,854,566	4,658,777	9,744,506	5,720,000	3,720,000	3,220,000	29,917,849
6	Electric UG Distribution	2,933,492	3,250,000	6,750,000	6,250,000	3,750,000	3,000,000	25,933,492
7	Electric Reimbursable	75,000	100,000	100,000	100,000	100,000	100,000	575,000
8	Electric Transmission	2,656,556	8,950,000	9,600,000	4,300,000	800,000	7,000,000	33,306,556
9	Electric Transformers	1,020,000	1,150,000	1,250,000	1,250,000	1,400,000	1,500,000	7,570,000
10	Electric Meters	750,000	3,000,000	3,000,000	3,000,000	3,000,000	1,000,000	13,750,000
11	Electric Lighting & Signals	480,627	250,000	250,000	250,000	250,000	275,000	1,755,627
12	Electric Substations	6,918,873	13,839,630	5,900,000	5,700,000	2,400,000	7,350,000	42,108,503
13	Storm Expenses	1,000	1,000	1,000	1,000	1,000	1,000	6,000
14	AMI Smart Grid Metering							-
15	Nearman Unit 1		995,000	1,022,000	3,675,000	-	-	5,692,000
16	Nearman Common		1,090,000	1,870,000	1,450,000	550,000	-	4,960,000
17	Nearman CT5			1,000,000	13,000,000	52,000,000	8,500,000	74,500,000
18	Nearman General Annual Capital			1,000,000	2,000,000	3,000,000	3,000,000	9,000,000
19	Quindaro Unit 1		660,000	4,095,000	2,095,000	2,000,000	2,000,000	10,850,000
20	Quindaro Unit 2		90,000	1,680,000	2,400,000	2,000,000	4,000,000	10,170,000
21	Quindaro Common		830,000	2,465,000	2,355,000	2,225,000	2,225,000	10,100,000
22	Quindaro CT1			1,000,000				1,000,000
23	Quindaro CT2				1,355,000			1,355,000
24	Quindaro CT3			1,800,000				1,800,000
25	Electric Control Center		600,000	500,000	1,500,000	-	-	
26	**Total Electric Capital Projects**	**$ 18,987,450**	**$ 41,042,608**	**$ 58,425,706**	**$ 61,649,200**	**$ 82,444,200**	**$ 48,819,200**	**$ 308,768,364**
	Environmental/AQC Projects							
27	N1 LNB & OFA		$ 1,000,000	$ 16,000,000	$ 10,000,000			$ 27,000,000
28	Q2 LNB & OFA		2,000,000	11,000,000				13,000,000
29	**Total Environmental/AQC Projects**	**$ -**	**$ 3,000,000**	**$ 27,000,000**	**$ 10,000,000**	**$ -**	**$ -**	**$ 40,000,000**
	Common Projects							
30	Common Furnish and Equipment	$ 127,810	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 252,810
31	Common Facility Improvements	33,000	261,210	217,400	225,500	225,500	225,500	1,188,110
32	Common Grounds	-	10,000	10,000	10,000	10,000	10,000	50,000
33	Common Technology	768,711	360,000	360,000	360,000	360,000	360,000	2,568,711
34	Administrative Service Technology	366,300	435,000	440,000	445,000	445,000	445,000	2,576,300
35	Common Tele Communications	-	50,000	50,000	50,000	50,000	50,000	250,000
36	**Total Common Projects**	$ 1,295,821	$ 1,141,210	$ 1,102,400	$ 1,115,500	$ 1,115,500	$ 1,115,500	$ 6,885,931
37	**Electric Portion of Common Projects @ 80%**	**1,036,657**	**912,968**	**881,920**	**892,400**	**892,400**	**892,400**	**5,508,745**
38	**Total CIP**	**20,024,107**	**44,955,576**	**86,307,626**	**72,541,600**	**83,336,600**	**49,711,600**	**356,877,109**
39	**Environmental/AQC Projects**	-	3,000,000	27,000,000	10,000,000	-	-	40,000,000
40	**Net CIP After Environmental**	**20,024,107**	**41,955,576**	**59,307,626**	**62,541,600**	**83,336,600**	**49,711,600**	**316,877,109**
41	**Financing Recap**							
42	Series 2009 (25 yrs @ 5.00%)	8,500,000	30,000,000	9,347,844				55,272,000
43	Series 2010 (25 yrs @ 5.5%)	-	-	35,500,000	-	-	-	35,500,000
45	Series 2010 Environmental (20 yrs @ 5.5%)	-	3,000,000	27,000,000	10,000,000	-	-	40,000,000
46	Series 2012 (25 yrs @ 5.5%)	-	-	-	45,500,000	60,000,000	-	105,500,000
47	Series 2014 (25 yrs @ 5.5%)	-	-	-	-	-	25,500,000	25,500,000
48	**Net Amount to Cash Finance**	**11,524,107**	**11,955,576**	**14,459,782**	**17,041,600**	**23,336,600**	**24,211,600**	**102,529,265**

3.2.4 CIP Financing and Debt Service

As stated previously, the CIP is financed with revenue bonds when surplus cash is not available. Line 40 of Table 3-4 shows the total amount to be financed with bonds and cash after removing projects funded by the ESC. Lines 43 through 47 show the projected project costs that will be financed with bonds. Line 42 shows the use of the remaining proceeds from the 2009 Revenue Bonds. Revenue bonds are projected to be issued in 2010, 2012, and 2014. Line 48 shows the remaining CIP balance after bond financing, which will be financed with annual operating revenues. Cash financing ranges from $11.5 million in 2009 to $24.2 million in 2014.

The proposed CIP financing plan is summarized in Table 3-5. Line 2 shows the annual cash contribution from operating revenues. Lines 3 and 4 show the individual bond issues at par, including 2 percent issuance costs. Line 6 shows the annual uses of funds for capital and environmental projects.

Table 3-5
Capital Improvement Plan Financing

Line	Description	2010	2011	2012	2013	2014
1	**Beginning Fund Balance**	39,347,800	81,847,800	10,000,000	60,000,000	-
	Sources of Funds					
2	Cash Funded Capital Projects	11,955,600	14,459,800	17,041,600	23,336,600	24,211,600
3	Environmental Bond Proceeds at Par	40,820,000	-	-	-	-
4	Capital Bond Proceeds at Par	36,220,000		107,650,000		26,020,000
5	Total Sources	88,995,600	14,459,800	124,691,600	23,336,600	50,231,600
	Uses of Funds					
6	Capital Improvements	44,955,600	86,307,600	72,541,600	83,336,600	49,711,600
7	Debt Issuance Expense	1,540,000	-	2,150,000	-	520,000
8	Total Uses	46,495,600	86,307,600	74,691,600	83,336,600	50,231,600
9	**Ending CIP Fund Balance**	**$ 81,847,800**	**$ 10,000,000**	**$ 60,000,000**	**$ -**	**$ -**

Existing debt service is shown on line 50 of Table 3-3 and averages about $22.5 million through the study period. The projected debt service on the recommended 2010 capital bond is $1.0 million in the year of issuance and $2.7 million thereafter, as shown on line 51. The projected debt service on the recommended FY 2010 environmental bond is $1.1 million in the year of issuance and $3.4 million thereafter, as shown on line 52. Total existing and proposed annual debt service increases from $20.6 million in 2009 to $37.2 million in 2014.

3.2.5 Other Expenditures and Transfers

The electric utility transfers money to the Unified Government of Wyandotte County (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. In the future, the PILOT payment is expected to range from 9.9 percent to 12.8 percent of adjusted gross revenues (gross revenue less off system sales fuel revenue). For 2010, the UG has set the PILOT transfer at 12.8 percent. The gross transfer is shown on line 68 of Table 3-3 and ranges from $17.1 to $23.3 million under existing rates.

Other expenditures shown on lines 69 through 73 of Table 3-3 include the use of cash to finance the CIP on line 69 and funding for the heat pump program and economic development.

The net annual deficiency under existing rates is shown on line 78 of Table 3-3 and summarized on Table 3-6.

The cumulative operating deficiency from 2009 through 2014 is $106.4 million.

Table 3-6
Annual Surplus / (Deficiency) from Operations and Debt Service Coverage– Existing Rates

	Fiscal Year Ending December 31,				
Description	2010	2011	2012	2013	2014
Carryover from 2009 Budget	$ (3,328,400)				
Annual Surplus / (Deficiency)	(457,500)	(12,617,700)	(20,577,200)	(31,616,200)	(37,818,400)
Cumulative	$ (3,785,900)	$ (16,403,600)	$ (36,980,800)	$ (68,597,000)	$ (106,415,400)
Debt Service Coverage[1]	1.28	1.08	0.77	0.78	0.62

(1) Coverage calculation excludes PILOT revenue

3.3 Overall Revenue Adequacy and Adjustments to Rates

Based on the projection of revenue and revenue requirements, there are rate 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 3-6, annual debt service coverage for the electric utility, without the inclusion of PILOT revenue, under existing rates ranges from a high of 1.28 in 2010 to a low of .62 in 2014, which is below 1 times coverage and of course, well 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.

3.4 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 are:

Table 3-7
Recommended Base Rate Adjustments

	Fiscal Year Ending December 31,				
Description	2010	2011	2012	2013	2014
Base Rates	7.0%	7.0%	7.0%	7.0%	0.0%
ESC	1.0%	1.6%	0.0%	0.0%	0.0%
Date Effective	June 1, 2010	January 1, 2011	January 1, 2012	January 1, 2013	

The recommended minimum adjustments result in annual surpluses from 2010 through 2014. Target BPU financial policies are not met until 2013 and targeted debt service requirements are not met until 2014.

Debt service coverage is calculated as net revenues (gross revenues minus operating expenses) divided by the maximum future debt service payment. Under recommended rates and the planned debt financing, debt service coverage is forecast to fluctuate above and below the stated target of 1.60, but stabilized at the target in 2014. Debt service coverage under proposed rates is shown in Table 3-8.

Table 3-8
Debt Service Coverage Requirements

Line	Description	2009	2010	2011	2012	2013	2014
	Rate Covenant						
1	Net Revenue including PILOT Revenue	$47,902,300	$66,661,000	$74,496,700	$77,607,900	$89,412,600	$85,981,300
2	Maximum Annual Debt Service Requirements - Total Debt	$22,956,294	$29,072,262	$28,484,619	$36,505,218	$36,505,218	$38,444,992
3	Coverage Ratio	2.09	2.29	2.62	2.13	2.45	2.24
4	Target	1.20					
	Financial Guidelines						
5	Net Revenue including PILOT Revenue	$47,902,300	$66,661,000	$74,496,700	$77,607,900	$89,412,600	$85,981,300
6	Maximum Annual Debt Service Requirements - Total Debt	$22,956,294	$29,072,262	$28,484,619	$36,505,218	$36,505,218	$38,444,992
7	Coverage Ratio	2.09	2.29	2.62	2.13	2.45	2.24
8	Target	1.60					
9	Net Revenue excluding PILOT Revenue	$30,815,100	$42,647,900	$49,476,100	$55,622,300	$65,581,200	$61,370,300
10	Maximum Annual Debt Service Requirements - Total Debt	$22,956,294	$29,072,262	$28,484,619	$36,505,218	$36,505,218	$38,444,992
11	Coverage Ratio	1.34	1.47	1.74	1.52	1.80	1.60
12	Target	1.60					

3.5 Utility Operations Under Recommended Rates

The forecast of financial operations under recommended rates are presented in Table 3-9. As shown on line 64 of Table 3-9, the recommended rates result in annual surpluses in each year. Total electric utility debt service coverage without PILOT revenue ranges from 1.34 to 1.80, as shown on line 76 Table 3-9.

Table 3-9
Projected Revenues Under Recommended Rates
Electric Utility
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				[A]	[B]	[C]	[D]	[E]	[F]
				For the Fiscal Year Ended:					
Line	Description			2009	2010	2011	2012	2013	2014
1	Retail Sales (MWh)			2,138,519	2,251,148	2,253,570	2,265,277	2,285,834	2,309,313
	REVENUES:								
	Base:								
2	Retail Base Revenue Existing Rates			103,049,800	108,530,000	108,429,500	109,065,400	110,190,300	111,524,800
	Additional Base Rate Revenue		Months in						
3	Date rate increase effective	% Increase	First Year						
4	June 1, 2010	7.00%	7		4,431,600	7,590,100	7,634,600	7,713,300	7,806,700
5	January 1, 2011	7.00%	12			8,121,400	8,169,000	8,253,300	8,353,200
6	January 1, 2012	7.00%	12				8,740,800	8,831,000	8,937,900
7	January 1, 2013	7.00%	12					9,449,200	9,563,600
8	January 1, 2014	0.00%	12						-
9	Recommended Base Rate Revenue Increases			-	4,431,600	15,711,500	24,544,400	34,246,800	34,661,400
10	Borderline			270,900	433,000	380,000	380,500	304,600	290,100
11	Nearman Participants			7,036,600	8,776,900	8,751,400	8,494,300	7,872,500	7,735,300
12	Off System Sales			568,800	3,560,800	2,558,300	2,683,400	2,339,700	1,100,000
13	**Total Base Revenue**			110,926,100	125,732,300	135,830,700	145,168,000	154,953,900	155,311,600
	Fuel:								
14	Retail ERC Revenue			55,156,000	54,625,700	64,500,400	67,498,900	74,473,900	82,385,300
15	Borderline Fuel Revenue			268,300	315,100	385,900	401,800	489,200	513,300
16	Nearman Participants Fuel Revenue			6,247,700	5,803,600	6,610,700	6,085,900	7,878,600	7,475,800
17	Off System Sales Fuel Revenue			5,399,400	8,154,100	7,621,500	8,897,000	8,445,400	5,496,300
18	**Total Fuel Revenue**			67,071,400	68,898,500	79,118,500	82,883,600	91,287,100	95,870,700
19	Environmental Surcharge Revenue			-	1,125,600	2,929,600	2,922,200	2,925,900	2,909,700
20	**Total Rate Revenue**			**177,997,500**	**195,756,400**	**217,878,800**	**230,973,800**	**249,166,900**	**254,092,000**
	Other Revenue:								
21	PILOT Rate			9.90%	12.80%	11.90%	9.90%	9.90%	9.90%
22	PILOT			17,087,200	24,013,100	25,020,600	21,985,600	23,831,400	24,611,000
23	Forfeited Discounts			2,142,000	2,184,800	2,228,500	2,273,100	2,318,600	2,365,000
24	Connect/Disconnect Fees			1,020,000	1,040,400	1,061,200	1,082,400	1,104,000	1,126,100
25	Tower/Pole Attachment Rentals			959,000	1,007,000	1,027,100	1,047,600	1,068,600	1,090,000
26	Ash Disposal			153,000	156,100	159,200	162,400	165,600	168,900
27	Diversion Fines			61,200	62,400	63,600	64,900	66,200	67,500
28	Service Fees			1,224,000	1,248,500	1,273,500	1,299,000	1,325,000	1,351,500
29	Other Miscellaneous Revenues			142,000	144,800	147,700	150,700	153,700	156,800
30	Investment Income			1,256,000	669,300	929,500	1,242,300	1,415,500	1,468,100
31	**Total Other Revenue**			**24,044,400**	**30,526,400**	**31,910,900**	**29,308,000**	**31,448,600**	**32,404,900**
32	**Total Revenue**			**202,041,900**	**226,282,800**	**249,789,700**	**260,281,800**	**280,615,500**	**286,496,900**
	REVENUES REQUIREMENTS:								
	Fuel Expense								
	Retail								
33	Generation Fuel Costs			33,565,500	33,237,000	40,485,000	39,874,700	50,164,900	48,191,000
34	Purchased Power			21,590,500	21,388,700	24,015,400	27,624,200	24,309,000	34,194,300
35	Total Retail Fuel			55,156,000	54,625,700	64,500,400	67,498,900	74,473,900	82,385,300
36	Borderline Fuel Costs			268,300	315,100	385,900	401,800	489,200	513,300
37	Nearman Participants Fuel Cost			6,247,700	5,803,600	6,610,700	6,085,900	7,878,600	7,475,800
38	Off System Fuel Costs			5,399,400	8,154,100	7,621,500	8,897,000	8,445,400	5,496,300
39	**Total Fuel Expense**			67,071,400	68,898,500	79,118,500	82,883,600	91,287,100	95,870,700
	Operation and Maintenance Expense								
40	Non-ERC Capacity Purchases			1,764,100	718,800	-	-	-	-
41	Production			38,777,700	41,763,100	46,015,800	47,290,300	45,370,700	48,059,200
42	Transmission			2,444,300	2,537,200	2,654,500	2,795,800	2,922,400	3,053,400
43	Distribution			20,110,700	20,713,800	21,578,400	22,690,900	23,622,300	24,584,200
44	Customer Accounts			5,503,300	5,768,400	5,961,300	6,191,700	6,380,600	6,512,100
45	Sales			481,500	499,400	514,200	533,000	548,900	565,300
46	Administrative and General			17,986,600	18,722,600	19,450,300	20,288,600	21,070,900	21,870,700
47	**Total O&M Expense**			87,068,200	90,723,300	96,174,500	99,790,300	99,915,800	104,644,900
48	**Total Expenses**			154,139,600	159,621,800	175,293,000	182,673,900	191,202,900	200,515,600
49	**Net Revenues**			47,902,300	66,661,000	74,496,700	77,607,900	89,412,600	85,981,300

Table 3-9
Projected Revenues Under Recommended Rates
Electric Utility
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		[A]	[B]	[C]	[D]	[E]	[F]
		For the Fiscal Year Ended:					
Line	Description	2009	2010	2011	2012	2013	2014
	Debt Service						
50	Existing Debt Service	20,644,000	22,956,300	22,368,700	22,345,700	22,361,700	22,364,000
51	2010 Capital Bonds ($36.2 million)	-	996,100	2,700,200	2,700,200	2,700,200	2,700,200
52	2010 Environmental Bonds ($40.8 million)	-	1,122,600	3,415,800	3,415,800	3,415,800	3,415,800
53	2012 Capital Bonds ($107.7 million)	-	-	-	2,960,400	8,025,200	8,025,200
54	2014 Capital Bonds ($26 million)	-	-	-	-	-	715,600
55	**Total Debt Service**	20,644,000	25,075,000	28,484,700	31,422,100	36,502,900	37,220,800
56	Balance Available for Transfers Out	27,258,300	41,586,000	46,012,000	46,185,800	52,909,700	48,760,500
	Proposed Uses of Balance Available for Transfers Out:						
57	PILOT	17,087,200	24,013,100	25,020,600	21,985,600	23,831,400	24,611,000
58	Cash Financed Capital Projects	11,524,100	11,955,600	14,459,800	17,041,600	23,336,600	24,211,600
59	Less: Reimbursable Projects	(786,400)	(714,400)	(734,700)	(755,700)	(764,700)	(764,700)
60	Capital Lease Payments	368,900	282,100	293,000	75,000	-	-
61	Heat Pump Program	449,900	449,900	449,900	449,900	449,900	449,900
62	Economic Development Fund Authorization	500,000	500,000	500,000	500,000	500,000	500,000
63	**Total Other Exp. And Transfers**	**29,143,700**	**36,486,300**	**39,988,600**	**39,296,400**	**47,353,200**	**49,007,800**
64	**Annual Operating Income**	(1,885,400)	5,099,700	6,023,400	6,889,400	5,556,500	(247,300)
	Operating Cash Balance						
65	Beg Balance	12,184,800	8,856,400	13,956,100	19,979,500	26,868,900	32,425,400
66	Cash Balance Adjustment	(1,443,000)					
67	Annual Cash Flow	(1,885,400)	5,099,700	6,023,400	6,889,400	5,556,500	(247,300)
68	End Balance	8,856,400	13,956,100	19,979,500	26,868,900	32,425,400	32,178,100
69	Target Days of O&M Expense	60	60	60	60	60	60
70	Target Operating Balance to Meet Financial Policies	25,338,000	26,239,200	28,815,300	30,028,600	31,430,600	32,961,500
71	Target Cash (Deficiency)/Surplus	(16,481,600)	(12,283,100)	(8,835,800)	(3,159,700)	994,800	(783,400)
	Debt Service Coverage Under Recommendd Rates						
	PILOT revenue included in coverage						
72	Parity Debt	**2.20**	**2.39**	**2.73**	**2.20**	**2.53**	**2.31**
73	Total System Achieved (Total Debt)	**2.09**	**2.29**	**2.62**	**2.13**	**2.45**	**2.24**
74	Target Minimum Coverage	1.60	1.60	1.60	1.60	1.60	1.60
	Without PILOT revenue						
75	Parity Debt	**1.42**	**1.53**	**1.82**	**1.58**	**1.86**	**1.65**
76	Total System Achieved (Total Debt)	**1.34**	**1.47**	**1.74**	**1.52**	**1.80**	**1.60**
77	Target Minimum Coverage	1.60	1.60	1.60	1.60	1.60	1.60
78	Days of O&M Reserved	**21**	**32**	**42**	**54**	**62**	**59**

As shown in Table 3-10, the recommended rates produce annual surpluses ranging from $5.1 million to $6.9 million in the years rate increases are implemented. These surpluses are used to gradually build up the operating reserve to meet stated targets by the end of the study period.

Table 3-10
Annual Surplus / (Deficiency) from Operations - Recommended Rates

	Fiscal Year Ending December 31,				
Description	2010	2011	2012	2013	2014
Beginning Balance 2009	$ 8,856,400				
Annual Surplus / (Deficiency)	5,099,300	$ 6,022,700	$ 6,889,400	$ 5,556,500	$ (247,300)
Total	$ 13,955,700	$ 6,022,700	$ 6,889,400	$ 5,556,500	$ (247,300)
Cumulative Cash Balance	$ 13,955,700	$ 19,978,400	$ 26,867,800	$ 32,424,300	$ 32,177,000

4.0 COST OF SERVICE ANALYSIS

This section presents the unbundled class cost of service analysis for the BPU electric system based on the projected FY 2010 base revenues and costs.

Table 4-1 presents a summary of Electric Utility revenue requirements, or cost of service to be allocated to classes, for test year 2010. Net revenue requirements include O&M expenses, debt service, capital expenditures, reserve fund obligations, and a margin adjustment. Credits to the cost of service include other revenues and interest income, which reduce base rate revenue requirements.

Pro forma adjustments, shown in Table 4-1, Column B, 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 wholesale, borderline and participation customers, or recommended to be recovered through the Environmental Surcharge (ESC), plus a margin adjustment. Column C, Table 4-1 presents the Test Year net cost of service of $116.1 million, Line 55, to be recovered through new base rates.

Table 4-2 presents a summary of the BPU's allocated cost of service requirements by class and a comparison to revenue by rate class under existing base rates. The total cost of service of $116.1 million exceeds the revenue under existing rates of $109.0 million. This is indicative of having a need for rate increases. However, despite the need for an overall adjustment to revenues, as shown on line 10 of Table 4-2, certain interclass subsidies exist and should be acknowledged by the BPU. The four primary rate classes (Residential, Small General Service, Large General Service, and Large Power Service) show an indicated percentage adjustment from plus 26.5 to negative 8.3 percent, which indicates an ineffective rate design that is not recovering revenue approximately equal to cost of service (Column F of Table 4-2).

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

Table 4-1
2010 Test Year Cost of Service - Electric Utility

Line	Description	[A] 2010 Test Year	[B] Pro Forma Adjustment	Note	[C] Test Year Base COS
	CASH BASIS:				
1	**Revenue Requirements:**				
2	**Fuel Expense**				
3	Retail				
4	Generation Fuel Costs	$ 33,237,000	$ (33,237,000)	(a)	$ -
5	Purchased Power	21,388,700	(21,388,700)	(a)	-
6	Total Retail Fuel	**$ 54,625,700**	**$ (54,625,700)**		**$ 0**
8	Borderline Fuel Costs	$ 315,100	$ (315,100)	(c)	$ -
9	Nearman Participants Fuel Cost	5,803,600	(5,803,600)	(c)	-
10	Off System Fuel Costs	8,154,100	(8,154,100)	(c)	-
11	**Total Fuel Expense**	**$ 14,272,800**	**$ (14,272,800)**		**$ 0**
12	**Operation and Maintenance Expense**				
13	Non-ERC Capacity Purchases	$ 718,800			$ 718,800
14	Production	41,763,100			41,763,100
15	Transmission	2,537,200			2,537,200
16	Distribution	20,713,800			20,713,800
17	Customer Accounts	5,768,400			5,768,400
18	Sales	499,400			499,400
19	Administrative and General	18,722,600			18,722,600
20	**Total O&M Expense**	**$ 90,723,300**	**$ 0**		**$ 90,723,300**
21	**Total Expenses**	**$ 159,621,800**	**$ (68,898,500)**		**$ 90,723,300**
22	**Debt Service**				
23	Existing Debt Service	$ 22,956,300			$ 22,956,300
24	2010 Capital Bonds ($36.2 million)	996,100			996,100
25	2010 Environmental Bonds ($40.8 million)	1,122,600		(b)	1,122,600
26	**Total Debt Service**	**$ 25,075,000**	**$ 0**		**$ 25,075,000**
27	**Recommended Uses of Balance Available for Transfers Out:**				
28	PILOT	$ 24,013,100	$ (24,013,100)	(d)	$ -
29	Cash Financed Capital Projects	11,955,600			11,955,600
30	Less: Reimbursable Projects	(714,400)			(714,400)
31	Capital Lease Payments	282,100			282,100
32	Heat Pump Program	449,900			449,900
33	Economic Development Fund Authorization	500,000			500,000
34	Deposit to Operating Reserve		5,099,700		5,099,700
35	**Total Other Exp. And Transfers**	**$ 36,486,300**	**$ (18,913,400)**		**$ 17,572,900**
36	**Total Revenue Requirements**	**$ 221,183,100**	**$ (87,811,900)**		**$ 133,371,200**
37	**Less: Other Revenue**				
38	**Other Revenue:**				
39	PILOT	$ 24,013,100	$ (24,013,100)	(d)	$ -
40	Forfeited Discounts	2,184,800			2,184,800
41	Connect/Disconnect Fees	1,040,400			1,040,400
42	Tower/Pole Attachment Rentals	1,007,000			1,007,000
43	Ash Disposal	156,100			156,100
44	Diversion Fines	62,400			62,400
45	Service Fees	1,248,500			1,248,500
46	Other Miscellaneous Revenues	144,800			144,800
47	Investment Income	669,300			669,300
48	Environmental Surcharge	1,125,600		(b)	1,125,600
49	Nearman Participants Margin	8,776,900			8,776,900
50	Borderline Margin	433,000			433,000
51	Off System Sales Margin	3,560,800			3,560,800
52	**Total Other Revenue**	**$ (44,422,700)**	**$ 24,013,100**		**$ (20,409,600)**
53	**Total Revenue Requirement**	**$ 176,760,400**	**$ (63,798,800)**		**$ 112,961,600**
54	**Margin Adjustment**		$ 3,165,500	(e)	$ 3,165,500
55	**Net Revenue Requirement**	**176,760,400**	**(60,633,300)**		**116,127,100**
56	**Revenues:**				
57	Retail Base Revenues	$ 108,530,000			$ 108,530,000
58	ERC Revenues	54,625,700	(54,625,700)	(a)	-
59	Borderline Fuel Costs	315,100	(315,100)	(c)	-
60	Nearman Participants Fuel Cost	5,803,600	(5,803,600)	(c)	-
61	Off System Fuel Costs	8,154,100	(8,154,100)	(c)	-
62	**Total Revenues**	**$ 177,428,500**	**$ (68,898,500)**		**$ 108,530,000**
63	**Base Revenue Increase:**				
64	Amount				**$ 7,597,100**
65	Percent				**7.00%**

(a) Fuel and Purchased Power recovered in ERC
(b) Environmental Debt Service recovered in ERSC and AQC Revenue from Nearman Participants
(c) Wholesale Fuel and Purchased Power recovered in Wholesale Revenue
(d) PILOT direct billed to customers, not included in Cost of Service
(e) Pro forma margin adjustment includes the full amount of revenue that would be recognized if a partial year rate increase were in place for the entire fiscal year.

Table 4-2
Summary of Cost of Service
Electric Utility

		[A]	[B]	[C]	[D]	[E]	[F]
Line	Description	2010 Retail Sales	Base Revenue Existing Rates	Base Net COS	Base COS Adjustment	Base Difference Amount	Base Difference Percent
		MWh				[C] + [D] - [B]	[E] / [B]
	TOTAL COST OF SERVICE						
1	Rate 100 - Residential	525,174	$ 33,582,542	$ 36,932,280	$ 1,891,405	$ 5,241,143	15.6%
2	Rate 200 - Small General Service	210,426	15,894,606	14,502,956	753,552	(638,098)	-4.0%
3	Rate 300 - Large General Service	659,877	33,504,839	29,234,973	2,126,707	(2,143,159)	-6.4%
4	Rate 400 - Large Power Service	796,030	20,771,681	23,878,657	2,399,809	5,506,785	26.5%
5	Rate 500 - School District	51,320	3,282,409	2,863,355	173,978	(245,076)	-7.5%
6	Rate 700 - Lighting	8,320	1,493,910	1,328,747	40,784	(124,379)	-8.3%
7	Borderline		433,029	900,335	(467,306) (1)	-	
8	KCK		-	4,903,701	(4,903,701) (1)	-	
9	BPU Interdepartmental		-	1,582,199	(1,582,199) (2)	-	
10	Total	$ 2,251,148	$ 108,963,016	$ 116,127,203	$ 433,029	$ 7,597,216	7.0%

(1) Allocated to Paying Classes on basis of Retail Sales, Column [A]
(2) Allocated to Paying Classes on basis of Base Net COS, Column [B]

4.1 Basis of Allocation

The Black & Veatch cost of service model is a two-dimensional cost matrix that allocates BPU total cost of service to each rate class. The resultant class cost of service requirements are divided by the class billing units to develop unbundled units of cost of service, which are used to guide the design base rates specific to the rate class. The cost of service analysis can be generally described as follows. The unbundled cost of service is analyzed first by function in order to properly allocate costs to the various classes of customers. These functions are classified to energy, capacity, number of customers, and direct assignments. Functional costs are then allocated to classes on the basis of each class' cost responsibility for energy, capacity, and customer related costs.

Energy related costs are considered to be expenses that vary with the number of kilowatt-hours sold. We classify 20 percent of boiler plant as energy related to reflect investment in environment and fuel handling plant associated with the production of energy. Capacity related costs include plant investment in the BPU's production facilities, transmission system, distribution system substations, line transformers, and a portion of distribution lines, as well as the associated operation and maintenance expense attributable to this plant.

Customer related costs include plant elements that are generally related to the number and type of customers served. Examples of customer related plant are services, meters, and a portion of distribution system lines. Based on our experience and review of BPU line data, Black & Veatch has allocated 55 percent of distribution lines investment to capacity related functions (Lines) and 45 percent to customer related functions (Laterals) including an allocation to lighting classes. Examples of other customer related expenses are meter reading and billing expense, customer installation expense, and sales expense.

The allocation of functionalized plant and cost of service components to classes are based upon the development of allocation factors in Tables 4-3 and 4-4. Table 4-3 shows the development of energy and capacity (demand) related allocation factors and Table 4-4 shows the development of customer related allocation factors. (For detail see tabs 'COS_Units (sales)' and 'COS_Units (cust)' in Model)

Table 4-3
Summary of Allocation Factors (Sales)

Line	Customer Class	[A] 2010 Sales	[B] Loss Factor	[C] Energy Responsibility Amount	[D] Energy Responsibility Percent	[E] Average Annual Demand	[F] Annual Load Factor Percent	[G] Maximum Class Demand Amount	[H] Maximum Class Demand Percent	[I] Coincidence Factor	[J] Maximum Non-Coincident Demand Amount	[K] Maximum Non-Coincident Demand Percent	[L] Primary Service Demand (excl. Prim. Amount	[M] Primary Service Demand (excl. Prim. Percent	[N] Class Excess Demand Amount	[O] Class Excess Demand Percent	[P] Allocated System Excess Demand	[Q] AED Responsibility Amount	[R] AED Responsibility Percent
		kWh		*kWh*		*kW*		*kW*			*kW*		*kW*		*kW*		*kW*	*kW*	
				[A] / (1-[B])	ENR1	[C]/8760		[E]/[F]	CAP1		[G]/[I]	CAP3	[G]/[I]	CAP3-P	[G] - [E]	CAP2		[E] + [P]	CAP4
1	Rate 100 - Residential	525,174,299	5.80%	557,509,871	22.68%	63,644	40.38%	157,612	26.96%	80.00%	197,069	29.57%	197,069	29.57%	93,968	31.55%	69,531	133,175	26.58%
2	Rate 200 - Small General Service	210,425,754	5.78%	223,328,757	9.08%	25,494	35.00%	72,840	12.46%	70.00%	104,058	15.61%	104,058	15.61%	47,346	15.90%	35,035	60,529	12.08%
3	Rate 300 - Large General Service	659,877,468	4.81%	693,238,531	28.20%	79,137	47.96%	165,001	28.22%	70.00%	235,961	35.40%	235,961	35.40%	85,864	28.83%	63,532	142,669	28.48%
4	Rate 400 - Large Power Service	796,030,443	2.51%	816,487,221	33.21%	93,206	66.43%	140,310	24.00%	80.00%	71,606	10.74%	71,606	10.74%	47,104	15.82%	34,854	128,060	25.56%
5	Rate 500 - School District	51,320,025	5.80%	54,479,856	2.22%	6,219	35.00%	17,769	3.04%	100.00%	17,769	2.67%	17,769	2.67%	11,550	3.88%	8,546	14,765	2.95%
7	Rate 700 - Lighting	8,319,612	5.80%	8,831,861	0.36%	1,007	39.99%	2,521	0.43%	100.00%	2,521	0.38%	2,521	0.38%	-	0.00%	-	1,007	0.20%
6	Borderline	18,398,591	4.00%	19,165,199	0.78%	2,188	45.00%	4,862	0.83%	70.00%	6,946	1.04%	6,946	1.04%	2,674	0.90%	1,979	4,167	0.83%
8	KCK	49,344,633	4.72%	51,787,069	2.11%	5,913	41.74%	14,163	2.42%	84.00%	16,874	2.53%	16,874	2.53%	3,528	1.18%	2,609	8,522	1.70%
9	BPU Interdepartmental	31,805,755	5.50%	33,656,884	1.37%	3,842	40.00%	9,605	1.64%	70.00%	13,722	2.06%	13,722	2.06%	5,763	1.94%	4,264	8,106	1.62%
10	Total	2,350,696,578	4.38%	2,458,485,249	100.00%	280,650	48.00%	584,683	100.00%		666,526	100.00%	666,526	100.00%	297,797	100.00%	220,350	501,000	100.00%

System Net Peak Demand 501,000

System Excess Demand 220,350

Table 4-4
Summary of Allocation Factors (Customers)

Line	Customer Class	[A] Average Number of Customers	[B] Customer Related Cost Responsibility Weighting Factors	[C] Customer Related Cost Responsibility Weighted No. of Customers	[D] Customer Related Cost Responsibility Percent	[E] Services Weighting Factors	[F] Services Weighted No. of Customers	[G] Services Percent	[H] Meters Weighting Factors	[I] Meters Weighted No. of Customers	[J] Meters Percent	[K] Laterals and Secondary Weighting Factors	[L] Laterals and Secondary Weighted No. of Customers	[M] Laterals and Secondary Percent	[N] Base Revenue Amount	[O] Base Revenue Percent	[P] Unweighted Cust Amount	[Q] Unweighted Cust Percent
				*[A] * [B]*	*CUS1*		*[A] * [E]*	*CUS2*		*[A] * [H]*	*CUS3*		*[A] * [K]*	*CUS4*		*REV*		*CUST*
1	Rate 100 - Residential	60,392	1.00	60,392	68.33%	1.00	60,392	69.79%	1.00	60,392	73.11%	1.00	60,347	78.30%	33,582,542	30.82%	60,392	89.37%
2	Rate 200 - Small General Service	6,529	2.00	13,058	14.78%	2.00	13,058	15.09%	2.01	13,145	15.91%	2.00	13,040	16.92%	15,894,606	14.59%	6,529	9.66%
3	Rate 300 - Large General Service	554	10.00	5,540	6.27%	14.57	8,070	9.33%	10.53	5,835	7.06%	4.86	2,690	3.49%	33,504,839	30.75%	554	0.82%
4	Rate 400 - Large Power Service	24	20.00	480	0.54%	7.29	175	0.20%	41.67	1,000	1.21%	0.00	-	0.00%	20,771,681	19.06%	24	0.04%
5	Rate 500 - School District	78	20.00	1,560	1.77%	10.00	780	0.90%	10.00	780	0.94%	2.00	156	0.20%	3,282,409	3.01%	78	0.12%
6	Rate 700 - Lighting	6,773	0.54	3,688	4.17%	0.04	245	0.28%	0.00	25	0.03%	0.00	-	0.00%	1,493,910	1.37%	-	0.00%
7	Borderline	119	5.00	595	0.67%	5.00	595	0.69%	2.00	238	0.29%	2.00	238	0.31%	433,029	0.40%	-	0.00%
8	KCK	19,968	0.14	2,745	3.11%	0.14	2,895	3.35%	0.03	546	0.66%	0.03	532	0.69%	-	0.00%	-	0.00%
9	BPU Interdepartmental	64	5.00	320	0.36%	5.00	320	0.37%	10.00	640	0.77%	1.00	64	0.08%	-	0.00%	-	0.00%
10	TOTAL ALL GROUPS	94,501		88,378	100.00%		86,530	100.00%		82,601	100.00%		77,067	100.00%	108,963,016	100.00%	67,577	100.00%

4.2 Allocation to Classes

The energy allocator (ENR1), shown in Column D of Table 4-3, is based on projected sales for test year 2010, including an allowance for system energy losses. The average loss factor (Column B) for the BPU's electric system is nominally 4.4 percent. Energy losses vary by class of customer to reflect the delivered energy losses to serve secondary voltage, primary voltage and substation voltage connected customers.

The average and excess demand (AED) method for allocation of system capacity costs is used because it gives recognition to both peak demand and the annual average demand (proportional to annual energy use) use of system capacity designed to deliver low cost energy. Under this method, a 100 percent load factor service class is allocated only the portion of the plant costs equal to its share of the capacity. Off-peak service classes, such as lighting, are assigned no excess demand and are allocated costs based on their average demand (energy use). Annual load factors for each customer class (Column F) are based on our experience with other utilities and consideration of class demand metered billing data obtained from the BPU.

In the AED method, each customer class is responsible for contributing to the system peak demand equal to at least the class average demand during the test year. System peak for firm load projected by the BPU is 501,000 kW. The difference between system peak demand and system average demand is system excess demand and is allocated to customer classes in proportion to respective class non-coincident excess demands (Table 4-3, Column K). The total demand responsibility of each customer class is the sum of the class average demand plus allocated excess demand. Column R shows the average and excess demand responsibility for each customer class. Street lighting and retail area lighting are not assigned excess capacity responsibility to reflect the off-peak nature of the load.

Customer related plant investment and expenses generally vary with the number of customers or the number of bills rendered. The development of customer related allocation factors is shown on Table 4-4. In order to recognize relative cost differences between facilities used to serve individual customers in the various customer classes, the number of customers is weighted using appropriate weighting factors based on our experience. We have developed allocation factors for customer related costs, services, meters, and laterals and line transformers. Because of the voluminous nature of the data involved with developing weighting factors and allocation factors for each rate class and multiple subgroups within each rate class, the detailed factors are not shown in this report, but can be reviewed in the Model that accompanies this report.

Table 4-5 shows the allocation of gross plant investment to functions based on gross plant in service for FY 2008. Production and transmission plant in service is functionally allocated using the average and excess allocators determined in Table 4-3, with the exception of Boiler Plant, which is allocated 20 percent on Energy and 80 percent on AED. Distribution Plant is direct allocated based on its use. Land, Structures, and Station Equipment are allocated to Substations; Overhead and Underground Lines and related assets are allocated 55 percent to Capacity (Lines), 38 percent to Customer (Laterals), and 7 percent to Street Lights and Private Area Lights. Line Transformers are direct assigned where data allows, and Services and Meters are allocated to customer functions. General plant is allocated to each function based on supervised expenses before general (a proxy for labor related costs). The detailed functionalization of plant can be found on the 'COS_RB' tab in the Model.

Table 4-5
Functional Classification of Plant in Service

		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	
				Production			Transmission Capacity			Capacity			Customers		Accounts	4%	3%				
Line	FERC Acct	Description	Total	Energy	Average	Excess	Average	Excess	Substations	Line Transformers	55% Lines	38% Laterals	Services	Meters	and Service	Street Lights	Private Area Lights	Direct to 400 Rate	Direct Assignment	Sales Revenue	Allocation Method
			$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	
		ORIGINAL PLANT																			
		Production Plant:																			
1	310	LAND & LAND RIGHTS	$ 1,694	$ -	$ 949	$ 745	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	AED
2	311	STRUCTURE IMPR	75,598	-	42,348	33,249	-	-	-	-	-	-	-	-	-	-	-	-	-	-	AED
3	312	BOILER PLANT	259,471	51,894	116,280	91,296	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20% Energy/80% AED
4	313	ENGINE & ENGINE GEN	60,946	-	34,141	26,805	-	-	-	-	-	-	-	-	-	-	-	-	-	-	AED
5	314	TURBOGENERATORS	94,377	-	52,868	41,509	-	-	-	-	-	-	-	-	-	-	-	-	-	-	AED
6	315	ACCESSORY ELECTRIC	42,579	-	23,852	18,727	-	-	-	-	-	-	-	-	-	-	-	-	-	-	AED
7	316	MISC POWER PLANT	6,601	-	3,698	2,903	-	-	-	-	-	-	-	-	-	-	-	-	-	-	AED
8		**Total Production Plant**	**$ 541,265**	**$ 51,894**	**$ 274,136**	**$ 215,235**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
9		**Transmission:**																			
10	350	LAND & LAND RIGHTS	$ 752	$ -	$ -	$ -	$ 421	$ 331	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	AED
11	351	CLEARING LAND	375	-	-	-	210	165	-	-	-	-	-	-	-	-	-	-	-	-	AED
12	352	STRUCTURES & IMPR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	AED
13	353	STATION EQUIPMENT	22,844	-	-	-	12,797	10,047	-	-	-	-	-	-	-	-	-	-	-	-	AED
14	354	TOWERS & FIXTURES	1,120	-	-	-	627	492	-	-	-	-	-	-	-	-	-	-	-	-	AED
15	355	POLES & FIXTURES	10,120	-	-	-	5,669	4,451	-	-	-	-	-	-	-	-	-	-	-	-	AED
16	356	OVERHEAD COND & DEV	13,215	-	-	-	7,403	5,812	-	-	-	-	-	-	-	-	-	-	-	-	AED
17	357	UNDERGROUND CONDUIT	84	-	-	-	47	37	-	-	-	-	-	-	-	-	-	-	-	-	AED
18	358	UNDRGRD COND & DEV	114	-	-	-	64	50	-	-	-	-	-	-	-	-	-	-	-	-	AED
19		**Total Transmission Assets**	**$ 48,624**	**$ -**	**$ -**	**$ -**	**$ 27,238**	**$ 21,386**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
20		**Distribution:**																			
21	360	LAND & LAND RIGHTS	$ 297	$ -	$ -	$ -	$ -	$ -	$ 297	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Substations
22	361	STRUCTURES & IMPR	7	-	-	-	-	-	7	-	-	-	-	-	-	-	-	-	-	-	Substations
23	362	STATION EQUIPMENT	46,792	-	-	-	-	-	46,792	-	-	-	-	-	-	-	-	-	-	-	Substations
24	364	POLES, TOWERS, & FIX	28,220	-	-	-	-	-	-	-	15,521	10,724	-	-	-	1,129	847	-	-	-	55% Lines/38% Laterals/4%SL/3%PAL
25	365	OVERHEAD COND & DEV	35,227	-	-	-	-	-	-	-	19,375	13,386	-	-	-	1,409	1,057	-	-	-	55% Lines/38% Laterals/4%SL/3%PAL
26	366	UNDERGROUND CONDUIT	9,868	-	-	-	-	-	-	-	5,427	3,750	-	-	-	395	296	-	-	-	55% Lines/38% Laterals/4%SL/3%PAL
27	367	UNDRGD COND & DEV	24,501	-	-	-	-	-	-	-	13,476	9,310	-	-	-	980	735	-	-	-	55% Lines/38% Laterals/4%SL/3%PAL
28	368	LINE TRANSFORMERS	36,706	-	-	-	-	-	-	35,075	-	-	-	-	-	-	-	1,631	-	-	Line Transformer/Direct
29	369	SERVICES	15,134	-	-	-	-	-	-	-	-	-	14,378	-	-	-	757	-	-	-	95% Services/5% PAL
30	370	METERS	10,597	-	-	-	-	-	-	-	-	-	-	10,597	-	-	-	-	-	-	Meters
31	371	INSTALLATIONS	261	-	-	-	-	-	-	-	-	-	-	-	-	-	261	-	-	-	PAL
32	373	ST LIGHT & SIGNAL SYS	18,972	-	-	-	-	-	-	-	-	-	-	-	-	18,972	-	-	-	-	Street Lights
33		**Total Distribution**	**$ 226,583**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 47,096**	**$ 35,075**	**$ 53,799**	**$ 37,170**	**$ 14,378**	**$ 10,597**	**$ -**	**$ 22,885**	**$ 3,952**	**$ 1,631**	**$ -**	**$ -**	
34		**Total Plant Before General Plant**	**$ 816,472**	**$ 51,894**	**$ 274,136**	**$ 215,235**	**$ 27,238**	**$ 21,386**	**$ 47,096**	**$ 35,075**	**$ 53,799**	**$ 37,170**	**$ 14,378**	**$ 10,597**	**$ -**	**$ 22,885**	**$ 3,952**	**$ 1,631**	**$ -**	**$ -**	
35		**Electric General Plant:**																			
36	389	LAND & LAND RIGHTS	$ 3,379	$ 463	$ 899	$ 644	$ 92	$ 72	$ 50	$ 19	$ 272	$ 188	$ 8	$ 222	$ 401	$ 33	$ 16	$ 1	$ -	$ -	Supervised O&M Before General
37	390	STRUCTURES & IMPR	40,934	5,612	10,888	7,802	1,118	876	602	233	3,291	2,272	94	2,685	4,859	397	192	12	-	-	Supervised O&M Before General
38	391	OFFICE FURN & EQUIP	11,371	1,559	3,025	2,167	310	243	167	65	914	631	26	746	1,350	110	53	3	-	-	Supervised O&M Before General
39	392	TRANSPORTATION EQUIP	12,302	1,687	3,272	2,345	336	263	181	70	989	683	28	807	1,460	119	58	4	-	-	Supervised O&M Before General
40	393	STORES EQUIP	248	34	66	47	7	5	4	1	20	14	1	16	29	2	1	0	-	-	Supervised O&M Before General
41	394	TOOLS SHOP, & WORK EQ	3,723	510	990	710	102	80	55	21	299	207	9	244	442	36	18	1	-	-	Supervised O&M Before General
42	395	LABORATORY EQUIP	85	12	22	16	2	2	1	0	7	5	0	6	10	1	0	0	-	-	Supervised O&M Before General
43	396	POWER OPERATED EQUIP	2	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	Supervised O&M Before General
44	397	COMMUNICATION EQUIP	1,399	192	372	267	38	30	21	8	112	78	3	92	166	14	7	0	-	-	Supervised O&M Before General
45	398	MISC EQUIP	34	5	9	6	1	1	1	0	3	2	0	2	4	0	0	0	-	-	Supervised O&M Before General
46		**Total Electric General Plant**	**$ 73,477**	**$ 10,074**	**$ 19,545**	**$ 14,005**	**$ 2,006**	**$ 1,572**	**$ 1,080**	**$ 419**	**$ 5,908**	**$ 4,078**	**$ 169**	**$ 4,820**	**$ 8,722**	**$ 713**	**$ 345**	**$ 22**	**$ -**	**$ -**	
47		**Common General Plant:**																			
48	390C	STRUCTURE & IMPR	$ 5,571	$ 764	$ 1,482	$ 1,062	$ 152	$ 119	$ 82	$ 32	$ 448	$ 309	$ 13	$ 365	$ 661	$ 54	$ 26	$ 2	$ -	$ -	Supervised O&M Before General
49	391C	OFFICE FURN & EQUIP	27,322	3,746	7,268	5,208	746	585	402	156	2,197	1,516	63	1,792	3,243	265	128	8	-	-	Supervised O&M Before General
50	392C	TRANSPORTATION EQUIP	466	64	124	89	13	10	7	3	37	26	1	31	55	5	2	0	-	-	Supervised O&M Before General
51	394C	TOOLS, SHOP, & EQUIP	93	13	25	18	3	2	1	1	8	5	0	6	11	1	0	0	-	-	Supervised O&M Before General
52	397C	COMMUNICATION EQUIP	10,875	1,491	2,893	2,073	297	233	160	62	874	604	25	713	1,291	105	51	3	-	-	Supervised O&M Before General
53	398C	MISC EQUIP	648	89	172	123	18	14	10	4	52	36	1	42	77	6	3	0	-	-	Supervised O&M Before General
54		**Total Common General Plant**	**$ 44,975**	**$ 6,166**	**$ 11,963**	**$ 8,572**	**$ 1,228**	**$ 962**	**$ 661**	**$ 256**	**$ 3,616**	**$ 2,496**	**$ 103**	**$ 2,950**	**$ 5,339**	**$ 436**	**$ 211**	**$ 13**	**$ -**	**$ -**	
55		**Total Original Cost**	**$ 934,924**	**$ 68,134**	**$ 305,644**	**$ 237,812**	**$ 30,472**	**$ 23,921**	**$ 48,837**	**$ 35,750**	**$ 63,323**	**$ 43,745**	**$ 14,650**	**$ 18,368**	**$ 14,060**	**$ 24,034**	**$ 4,509**	**$ 1,667**	**$ -**	**$ -**	

Table 4-6 presents a summary of the allocation of test year revenue requirements. Operation and maintenance expenses, debt service, capital expenditures, payment to the City, margin adjustment, and other operating revenue are allocated to functions. The bases of allocations are shown in detail on the 'COS_RR' tab in the Model.

Table 4-7 presents a summary of the class allocation factors for each function. The detail supporting these allocation factors are shown in the Model on the 'COS_Alloc' tab. Table 4-8 presents a summary of the unbundled cost of service by function, which is allocated to classes on the basis of allocation factors summarized in Table 4-7. The detailed unbundled cost of service by rate class detail is shown in the Model on the 'COS_Unbun.' tab.

Table 4-9 presents the unbundled unit cost of service by class. This table takes the results of Table 4-8 and divides the costs by appropriate class billing units to determine unit costs of service. For example, customer related costs are divided by the number of bills. Energy related costs are divided by kWh billing units. Capacity related costs are divided by kWh or kW billing units appropriate to the metering basis of the class. These unit costs are used as guides in designing class base rates. The detailed unit cost calculations are on the 'COS_Unit' tab in the Model.

Table 4-6
Functional Classification of Cost of Service

		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]	[P]	[Q]	[R]
			Production			Transmission Capacity		Capacity				Customers		Accounts	4%	3%			
Line	Description	Total	Energy	Average	Excess	Average	Excess	Substations	Line Transformers	55% Lines	38% Laterals	Services	Meters	and Service	Street Lights	Private Area Lights	Direct to 400 Rate	Number of Customers	Base Revenue
		$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
	Revenue Requirements:																		
1	Production O&M	$ 41,763	$ 14,615	$ 15,206	$ 11,942	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Transmission O&M	2,537	-	-	-	1,421	1,116	-	-	-	-	-	-	-	-	-	-	-	-
3	Distribution O&M	20,714	376	1,985	1,559	627	493	1,442	899	4,850	3,351	368	3,243	136	1,016	328	42	-	-
4	Customer Accounts O&M	5,768	-	-	-	-	-	-	-	-	-	-	-	5,768	-	-	-	-	-
5	Sales O&M	499	-	-	-	-	-	-	-	-	-	-	-	499	-	-	-	-	-
6	Admin & General O&M	18,723	2,561	4,673	3,671	511	401	223	154	1,575	1,088	62	1,241	2,252	210	94	7	-	-
7	Non-ERC Capacity Purchases	719	719	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Retail Generation Fuel Costs in ERC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Purchased Power Fuel Costs in ERC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Fuel - Wholesale	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Debt Service Existing	22,956	1,460	7,706	6,051	767	601	1,325	987	1,513	1,045	404	298	-	643	110	46	-	-
12	Debt Service Proposed	996	43	227	178	54	43	94	70	107	74	29	21	-	46	8	3	-	-
13	Debt Service Environmental	1,123	1,123	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	PILOT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Other Expenses	5,617	462	2,068	1,624	204	161	325	242	35	24	99	124	95	134	9	11	-	-
16	Cash Financed Capital Projects	11,956	493	897	705	925	727	1,473	1,095	1,937	1,338	448	561	433	735	137	51	-	-
17	**Total Revenue Requirements**	**$ 133,371**	**$ 21,852**	**$ 32,762**	**$ 25,732**	**$ 4,511**	**$ 3,540**	**$ 4,881**	**$ 3,446**	**$ 10,016**	**$ 6,919**	**$ 1,410**	**$ 5,488**	**$ 9,184**	**$ 2,783**	**$ 686**	**$ 161**	**$ -**	**$ -**
18	**Other Income Sources:**																		
19	Other Revenue	$ (18,615)	$ (1,339)	$ (6,248)	$ (4,907)	$ -	$ -	$ (30)	$ (22)	$ (588)	$ (406)	$ (9)	$ (7)	$ (62)	$ (55)	$ (33)	$ (1)	$ (4,907)	$ -
20	Investment Income	(669)	(49)	(217)	(171)	(22)	(17)	(35)	(26)	(46)	(32)	(11)	(13)	(10)	(17)	(3)	(1)	-	-
21	Environmental Surcharge Revenue	(1,126)	(1,126)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	**Total Other Income Sources**	**$ (20,410)**	**$ (2,514)**	**$ (6,465)**	**$ (5,077)**	**$ (22)**	**$ (17)**	**$ (65)**	**$ (48)**	**$ (634)**	**$ (438)**	**$ (20)**	**$ (20)**	**$ (73)**	**$ (72)**	**$ (36)**	**$ (2)**	**$ (4,907)**	**$ -**
23	**Total Net Revenue Requirements**	**$ 112,962**	**$ 19,338**	**$ 26,297**	**$ 20,654**	**$ 4,489**	**$ 3,523**	**$ 4,816**	**$ 3,398**	**$ 9,382**	**$ 6,481**	**$ 1,390**	**$ 5,468**	**$ 9,111**	**$ 2,711**	**$ 650**	**$ 159**	**$ (4,907)**	**$ -**
24	Margin Adjustment	3,166	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,166
25	**Total Cost of Service**	**$ 116,127**	**$ 19,338**	**$ 26,297**	**$ 20,654**	**$ 4,489**	**$ 3,523**	**$ 4,816**	**$ 3,398**	**$ 9,382**	**$ 6,481**	**$ 1,390**	**$ 5,468**	**$ 9,111**	**$ 2,711**	**$ 650**	**$ 159**	**$ (4,907)**	**$ 3,166**

Table 4-7
Summary of Allocation Factors by Function

		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]	[U]	[V]	[W]
									Distribution							Customer								
		Production				Transmission			Capacity					Customers		Accounts	4%	3%						
		Energy		Capacity			Capacity				Line	55%	38%			and	Street	Private Area	Direct to	Number of	Sales			
Line	Customer Class	Average	Excess	Average	Excess	Average	Excess	Excess	Substations		Transformers	Lines	Laterals	Services	Meters	Service	Lights	Lights	400 Rate	Customers	Revenue		Energy	
1	**COS_Units Reference**	*ENR1*	*ENR1-M*	*ENR1*	*CAP2*	*ENR1*	*CAP2*	*CAP2-M*	*CAP1*	*CAP1-M*	*CAP3-P*	*CAP3*	*CUS4*	*CUS2*	*CUS3*	*CUS1*	*SL*	*TL*	*CB*	*CUST*	*REV*	*REV-M*	*ENR*	*ENR-M*
2	**COS_Unbundled Reference**	*ENR1 PE*	*ENR1-M PE*	*ENR1 PC*	*CAP2 PC*	*ENR1 TC*	*CAP2 TC*	*CAP2-M TC*	*CAP1 DC*	*CAP1-M DC*	*CAP3-P DLT*	*CAP3 0.55*	*CUS4 0.38*	*CUS2 CS*	*CUS3 CM*	*CUS1 A&S*	*SL*	*TL*	*CB*	*CUST*	*REV SR*	*REV-M SR*	*ENR*	*ENR-M*
3	Rate 100 - Residential	22.68%	22.68%	22.68%	31.55%	22.68%	31.55%	31.55%	26.96%	26.96%	29.57%	29.57%	78.30%	69.79%	73.11%	68.33%	0.00%	0.00%	0.00%	89.37%	30.82%	30.82%	22.34%	22.68%
4	Rate 200 - Small General Servic	9.08%	9.08%	9.08%	15.90%	9.08%	15.90%	15.90%	12.46%	12.46%	15.61%	15.61%	16.92%	15.09%	15.91%	14.78%	0.00%	0.00%	0.00%	9.66%	14.59%	14.59%	8.95%	9.08%
5	Rate 300 - Large General Servic	28.20%	28.20%	28.20%	28.83%	28.20%	28.83%	28.83%	28.22%	28.22%	35.40%	35.40%	3.49%	9.33%	7.06%	6.27%	0.00%	0.00%	0.00%	0.82%	30.75%	30.75%	28.07%	28.20%
6	Rate 400 - Large Power Service	33.21%	33.21%	33.21%	15.82%	33.21%	15.82%	15.82%	24.00%	24.00%	10.74%	10.74%	0.00%	0.20%	1.21%	0.54%	0.00%	0.00%	100.00%	0.04%	19.06%	19.06%	33.86%	33.21%
7	Rate 500 - School District	2.22%	2.22%	2.22%	3.88%	2.22%	3.88%	3.88%	3.04%	3.04%	2.67%	2.67%	0.20%	0.90%	0.94%	1.77%	0.00%	0.00%	0.00%	0.12%	3.01%	3.01%	2.18%	2.22%
8	Rate 700 - Lighting	0.36%	0.36%	0.36%	0.00%	0.36%	0.00%	0.00%	0.43%	0.43%	0.38%	0.38%	0.00%	0.28%	0.03%	4.17%	0.00%	100.00%	0.00%	0.00%	1.37%	1.37%	0.35%	0.36%
9	Borderline	0.78%	0.78%	0.78%	0.90%	0.78%	0.90%	0.90%	0.83%	0.83%	1.04%	1.04%	0.31%	0.69%	0.29%	0.67%	0.00%	0.00%	0.00%	0.00%	0.40%	0.40%	0.78%	0.78%
10	KCK	2.11%	2.11%	2.11%	1.18%	2.11%	1.18%	1.18%	2.42%	2.42%	2.53%	2.53%	0.69%	3.35%	0.66%	3.11%	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.10%	2.11%
11	BPU Interdepartmental	1.37%	1.37%	1.37%	1.94%	1.37%	1.94%	1.94%	1.64%	1.64%	2.06%	2.06%	0.08%	0.37%	0.77%	0.36%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.35%	1.37%
12	**Total System**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**	**100.00%**

Table 4-8
Summary Allocation of Cost of Service to Classes

		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]	[P]	[Q]	[R]
								Distribution						Customer					
			Production			Transmission		Capacity				Customers		Accounts	4%	3%			
						Capacity			Line	55%	38%			and	Street	Private	Direct to	Number of	Sales
Line	Customer Class	Total	Energy	Average	Excess	Average	Excess	Substations	Transformers	Lines	Laterals	Services	Meters	Service	Lights	Area Lights	400 Rate	Customers	Revenue
	Total Rev Requirements		*ENR1 PE*	*ENR1 PC*	*CAP2 PC*	*ENR1 TC*	*CAP2 TC*	*CAP1 DC*	*CAP3-P DLT*	*CAP3 0.55*	*CUS4 0.38*	*CUS2 CS*	*CUS3 CM*	*CUS1 A&S*	*SL*	*TL*	*CB*	*CUST*	*REV SR*
1	Rate 100 - Residential	$ 36,932,280	$ 4,385,281	$ 5,963,405	$ 6,517,253	$ 1,017,909	$ 1,111,752	$ 1,298,329	$ 1,004,662	$ 2,774,064	$ 5,074,936	$ 970,414	$ 3,997,570	$ 6,226,104	$ -	$ -	$ -	$ (4,385,009)	$ 975,610
2	Rate 200 - Small General Service	14,502,956	1,756,684	2,388,860	3,283,743	407,761	560,160	600,020	530,490	1,464,784	1,096,616	209,821	870,118	1,346,212	-	-	-	(474,071)	461,758
3	Rate 300 - Large General Service	29,234,973	5,452,893	7,415,215	5,955,212	1,265,724	1,015,876	1,359,208	1,202,930	3,321,528	226,224	129,673	386,245	571,126	-	-	-	(40,234)	973,353
4	Rate 400 - Large Power Service	23,878,657	6,422,329	8,733,520	3,266,950	1,490,748	557,295	1,155,809	365,054	1,007,982	-	2,813	66,198	49,482	-	-	158,788	(1,753)	603,442
5	Rate 500 - School District	2,863,355	428,530	582,745	801,071	99,470	136,652	146,374	90,586	250,126	13,118	12,533	51,631	160,823	-	-	-	(5,662)	95,358
6	Rate 700 - Lighting	1,328,747	69,501	94,513	-	16,130	-	20,759	12,866	35,521	-	3,938	1,656	380,214	-	650,251	-	-	43,398
7	Borderline	900,335	150,759	205,013	185,454	34,994	31,636	40,053	35,410	97,774	20,013	9,560	15,752	61,337	-	-	-	-	12,580
8	KCK	4,903,701	407,355	553,950	244,669	94,555	41,738	116,662	86,026	237,534	44,739	46,519	36,148	282,998	2,710,808	-	-	-	-
9	BPU Interdepartmental	1,582,199	264,737	360,008	399,699	61,451	68,183	79,123	69,957	193,165	5,379	5,142	42,363	32,992	-	-	-	-	-
10	**Total**	**$ 116,127,203**	**$ 19,338,069**	**$ 26,297,229**	**$ 20,654,051**	**$ 4,488,742**	**$ 3,523,292**	**$ 4,816,337**	**$ 3,397,981**	**$ 9,382,478**	**$ 6,481,025**	**$ 1,390,413**	**$ 5,467,681**	**$ 9,111,288**	**$ 2,710,808**	**$ 650,251**	**$ 158,788**	**$ (4,906,729)**	**$ 3,165,499**

Table 4-9
Unbundled Unit Rates

		[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]	[P]	[Q]	[R]
				Production		Transmission		Distribution				Customers		Customer	4%	3%			
						Capacity		Capacity						Accounts	Street	Private			
									Line	55%	38%			and			Base	Total	Total
Line	Customer Class	Total	Energy	Average	Excess	Average	Excess	Substations	Transformers	Lines	Laterals	Services	Meters	Service	Lights	Area Lights	Revenue	Revenue	Unit Cost
	Energy Sales (kWh)																		
1	Rate 100 - Residential	525,174,299	$ 0.00835	$ 0.01136	$ 0.01241	$ 0.00194	$ 0.00212	$ 0.00247	$ 0.00191	$ 0.00528	$ 0.00966	$ 0.00185	$ 0.00761	$ 0.01186	$ -	$ -	$ -	$ (0.00835)	$ 0.00186
2	Rate 200 - Small General Service	210,425,754	0.00835	0.01135	0.01561	0.00194	0.00266	0.00285	0.00252	0.00696	0.00521	0.00100	0.00414	0.00640	-	-	-	(0.00225)	0.00219
3	Rate 300 - Large General Service	659,877,468	0.00826	0.01124	0.00902	0.00192	0.00154	0.00206	0.00182	0.00503	0.00034	0.00020	0.00059	0.00087	-	-	-	(0.00006)	0.00148
4	Rate 400 - Large Power Service	796,030,443	0.00807	0.01097	0.00410	0.00187	0.00070	0.00145	0.00046	0.00127	-	0.00000	0.00008	0.00006	-	-	0.00020	(0.00000)	0.00076
5	Rate 500 - School District	51,320,025	0.00835	0.01136	0.01561	0.00194	0.00266	0.00285	0.00177	0.00487	0.00026	0.00024	0.00101	0.00313	-	-	-	(0.00011)	0.00186
6	Rate 700 - Lighting	8,319,612	0.00835	0.01136	-	0.00194	-	0.00250	0.00155	0.00427	-	0.00047	0.00020	0.04570	-	0.07816	-	-	0.00522
7	Borderline	18,398,591	0.00819	0.01114	0.01008	0.00190	0.00172	0.00218	0.00192	0.00531	0.00109	0.00052	0.00086	0.00333	-	-	-	-	0.00068
8	KCK	49,344,633	0.00826	0.01123	0.00496	0.00192	0.00085	0.00236	0.00174	0.00481	0.00091	0.00094	0.00073	0.00574	0.05494	-	-	-	-
9	BPU Interdepartmental	31,805,755	0.00832	0.01132	0.01257	0.00193	0.00214	0.00249	0.00220	0.00607	0.00017	0.00016	0.00133	0.00104	-	-	-	-	-
10	**Total**	2,350,696,578	$ 0.00823	$ 0.01119	$ 0.00879	$ 0.00191	$ 0.00150	$ 0.00205	$ 0.00145	$ 0.00399	$ 0.00276	$ 0.00059	$ 0.00233	$ 0.00388	$ 0.00115	$ 0.00028	$ (0.00209)	$ 0.00135	$ 0.04933
	Demand	Facilities Demand	Billed Demand																
11	Rate 100 - Residential	-	-	-	-	-	-	-	-	-									$ -
12	Rate 200 - Small General Service	88,674	33,797	70.68	97.16	12.06	16.57	6.77	5.98	16.52									$ 225.75
13	Rate 300 - Large General Service	181,317	131,969	56.19	45.13	9.59	7.70	7.50	6.63	18.32									$ 151.05
14	Rate 400 - Large Power Service	155,794	110,222	79.24	29.64	13.53	5.06	7.42	2.34	6.47									$ 143.69
15	Rate 500 - School District	-	-	-	-	-	-	-	-	-									$ -
16	Rate 700 - Lighting	-	-	-	-	-	-	-	-	-									$ -
17	Borderline	-	-	-	-	-	-	-	-	-									$ -
18	KCK	7,521	4,368	90.07	123.90	15.37	21.14	8.38	7.43	20.53									$ 286.82
19	BPU Interdepartmental	-	-	-	-	-	-	-	-	-									$ -
20	**Total**	433,306	280,356	$ 93.80	$ 73.67	$ 16.01	$ 12.57	$ 11.12	$ 7.84	$ 21.65									$ 236.66
	Annual Bills																		
21	Rate 100 - Residential	724,704									$ 7.00	$ 1.34	$ 5.52	$ 8.59					$ 22.45
22	Rate 200 - Small General Service	78,348									14.00	2.68	11.11	17.18					44.96
23	Rate 300 - Large General Service	6,624									34.15	19.58	58.31	86.22					198.26
24	Rate 400 - Large Power Service	180									0.00	15.63	367.77	274.90					658.29
25	Rate 500 - School District	936									14.01	13.39	55.16	171.82					254.39
26	Rate 700 - Lighting	81,276									0.00	0.05	0.02	4.68					4.75
27	Borderline	1,428									14.01	6.69	11.03	42.95					74.69
28	KCK	3,216									13.91	14.46	11.24	88.00					127.61
29	BPU Interdepartmental	768									7.00	6.70	55.16	42.96					111.82
30	**Total**	897,480									$ 7.22	$ 1.55	$ 6.09	$ 10.15					$ 25.01

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 allowed 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 access 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 access charge and seasonally differentiated kilowatt-hour charges are sufficient elements of the multi part rate. For larger customers, a combination of these elements permit 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; and
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 modifications 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 earn its return in the "Rate Effective Period". The Rate Effective Period is typically the first twelve months after the new rates take effect.

5.2 Rate Design Practice

In practice, rates must be redesigned 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 A provides a revised Rate Application Manual. Recommended changes to the Rate Application Manual include the following:

- Adding new definitions for billing cycle, customer and term of contract
- Modifying definitions for customer charge to customer access charge, demand and demand charge, energy rate component, summer and winter base rate periods. Summer is defined as the four months May through August. Winter is the remaining eight months. For cycle billed customers, the summer bills are bills rendered for four cycles after May 15
- In each rate schedule replacing the term customer charge with customer access charge to more clearly define the nature of the cost
- Modifying the minimum bill provision to include the customer access charge, facilities demand and other applicable demand charges
- Establishing a minimum usage requirement for installation of a demand meter for the Small General Service rate
- Modifying the definition of billing demand to reflect seasonal and time of use provisions where applicable
- Changing the Metering credit provisions in the tariffs from a billed revenue adjustment to a metered kW and kWh adjustment
- Adding a term of contract provision to general service rate schedules
- Eliminating the ERC provision related to service voltage consistent with the metering credit provisions
- Adjusting the ERC Purchase Power definition to include all generation and transmission capacity charges that may be assessed by the Southwest Power Pool related to transmission market operations including energy imbalance, day-ahead energy, capacity and ancillary service markets.

- Increasing the frequency of the ERC adjustment to a quarterly adjustment with reconciliation adjustments to occur 90 days after the close of the quarter to track fuel costs to rates more closely
- Adding an Electric Heating rate for the Residential rate class
- Adding an Environmental Surcharge rider
- Removing the Economic Development Rider from the Rate Manual. Economic development activities will be based on future policy direction
- Adding a Medium General Service rate class, and dividing the existing Large General Service rate class into two classes to track costs better

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

With respect to individual rates, the changes applicable to the first year rates are discussed below. The changes have focused on recovery of fixed costs in fixed charges to the extent practicable and to introducing improved seasonal billing provisions. Based on a statistical analysis of hourly costs, the optimal summer season includes the months of May through August. Using these months' results in the largest seasonal difference in cost and the smallest cost differences during the season. The proposed rates include seasonal energy charges for all rate classes.

The rate process began 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. As a general rule, no class will receive an annual rate increase greater than 50% above the system average rate increase. For classes recovering more than the indicated cost of service, either a lower than average increase, or no increase has been proposed. In each case the proposed increase is a target and the actual increase will be slightly different. Actual increase differs from the proposed because charges in the rate schedule should not be carried to the point that they produce no revenue on individual bills but when applied to the total of all bills produce revenue. The process of rounding and truncating rate elements always causes slight deviations from target revenue. Usually these amount to a matter of thousands of dollars difference between the expected revenue and the revenue requirement. So long as the differences are small it is reasonable to consider them immaterial.

5.2.1 Residential Rate Class – Rate 100

The residential class is under recovering its cost of service by about 15.6 percent. Based on this under recovery, we propose to increase the class at a rate higher than the system average of 7 percent per year in the next three years and at the system average in the fourth year. The proposed changes to the residential base rate design reflect a target increase in the first year of 8.75 percent, which falls between the system average and the maximum class increase. Subsequent year recommended rate increases are 8.75 percent, 8 percent, and 7 percent in 2011 through 2013, respectively. The rate redesign includes the replacement of the customer charge with a Customer Access Charge. The Customer Access Charge is designed to cover the costs incurred to allow the customer to access and use power from the system. This change is designed to more accurately reflect the costs that customers pay for access to the system. Although this charge does not cover all of the costs of access, the rate is designed to move toward full recovery of access costs in the rate. The proposed charge is $12.25 per month. At this level, the charge represents about 55 percent of the cost of access.

With respect to changes to the Customer Access Charge, one concern is always 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 LIEAP 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 Access Charge, the lesser the impact on the kWh charges in the rate. As customers use power above the average the increase is proportionally lower. Third, the impact of the increase in the Customer Access Charge is less than 19 cents per day. We have concluded that the principles of efficiency, cost of service, non-discrimination and balanced budget are better served through a larger increase to the Customer Access Charge and lesser increases to the blocked energy charges.

The energy charge portion of the residential rate consists of three seasonally differentiated energy blocks. We have retained the existing structure for rate continuity but would note that as a practical matter the second and third block may be consolidated at some point in the future to further simplify the rate. Table 5-1 illustrates the current charges and the proposed charges in 2010 by block and season.

An additional Residential rate has been recommended for customers with electric heating facilities. The new Residential Electric Heating rate (Rate 101) has the same summer blocks as Rate 100, but has declining blocks in the winter months to promote use of electric heating.

Table 5-1
Present and Recommended Residential Energy Charges

Rate Blocks	Current Charge	2010 Recommended Charge	Percent Change
Rate 100 – Residential			
Summer	$/kWh	$/kWh	
First 1000 kWh	$0.0563	$0.0600	6.6 %
Next 1000 kWh	$0.0672	$0.0700	4.2 %
All Additional kWh	$0.0992	$0.0900	-9.3 %
Winter			
First 1000 kWh	$0.0563	$0.0475	-15.6 %
Next 1000 kWh	$0.0266	$0.0450	69.2 %
All Additional kWh	$0.0266	$0.0450	69.2 %
Rate 101 – Residential Electric Heating			
Summer	$/kWh	$/kWh	
First 1000 kWh	$0.0563	$0.0600	6.6 %
Next 1000 kWh	$0.0672	$0.0700	4.2 %
All Additional kWh	$0.0992	$0.0900	-9.3 %
Winter			
First 1000 kWh	$0.0563	$0.0475	-15.6 %
Next 1000 kWh	$0.0266	$0.0300	12.8 %
All Additional kWh	$0.0266	$0.0266	0.0 %

Given the winter season is proposed to be eight months instead of six months, the overall impact on residential rates from the redesign is small for several reasons. First, under the old definition of winter, the third block of the residential rate included less than 50,000 kWh suggesting that heating load impacts are limited to the second block of the rate. Further, the revised billing kWh under the new winter definition in the second block exhibit a substantial increase over the former definition suggesting that much of the impact of the rate change falls in shoulder months and will actually partially offset the large percentage increase in the charge because in those shoulder months the charge in the second and third blocks of the rate is actually a decrease for two months. The net result is that comparing the present and proposed energy rates impact on total winter revenue, the total revenue for the winter season declines by 8.75 percent despite the increase in the second and third block of the energy rate. For electric heating customers, the winter rate blocks have been adjusted to maintain the current energy charge for the last rate block. Total winter revenue will increase however as the result of the increased Customer Access Charge.

Table 5-2 shows the impact on monthly residential bills for 2010 using the median usage from 2008 for a winter month (January) and a summer month (August). The average monthly increase in winter months is approximately $1, while the summer increase is about $10 more per month. The average monthly increase for 2010 is about $4.42 per month. The recommended Residential base rates are shown in Table 5-3.

Table 5-2
Impact of 2010 Recommended Rates on Monthly Residential Bills

	Class Median Monthly Usage(1)	Monthly Bill (2) Existing Rates	Monthly Bill (2) 2010 Recommended Rates	Change in Monthly Bill Under Recommended Rates	Percentage Increase
	kWh	$	$	$	
100 - Residential					
Winter	625	$57.04	$57.50	$0.46	0.8%
Summer	1,150	$101.04	$111.12	$10.08	10.0%
101 - Residential Electric Heating					
Winter	2,300	$153.59	$154.99	$1.40	0.9%
Summer	1,200	$105.62	$116.13	$10.51	10.0%

Total Residential Revenue Under Existing Rates	$46,395,140.10
Total Residential Revenue Under Recommended Rates	$49,599,489.51
Recommended First Year Revenue Increase (3)	$3,204,349.41
Total Number of Bills	724,704
Average Increase per Bill per Month	$4.42

Notes:
(1) Median usage for January 2008 and August 2008
(2) Monthly bill calculations include ERC Rider and ESC Rider, but no PILOT or taxes
(3) Revenue increase if rate was in effect for all of 2010

Table 5-3
Recommended 2010 Residential Base Rates

Description	Present Rate	Recommended Rate
100 - Residential		
Customer Charge	$ 6.60	$ 12.25
Energy Charge		
First 1000 kWh		
Summer (1)	$ 0.05630	$ 0.06000
Winter	$ 0.05630	$ 0.04750
Next 1000 kWh		
Summer (1)	$ 0.06720	$ 0.07000
Winter	$ 0.02660	$ 0.04500
All Additional kWh		
Summer (1)	$ 0.09920	$ 0.09000
Winter	$ 0.02660	$ 0.04500
101 - Residential Electric Heating		
Customer Charge	$ 6.60	$ 12.25
Energy Charge		
First 1000 kWh		
Summer (1)	$ 0.05630	$ 0.06000
Winter	$ 0.05630	$ 0.04750
Next 1000 kWh		
Summer (1)	$ 0.06720	$ 0.07000
Winter	$ 0.02660	$ 0.03000
All Additional kWh		
Summer (1)	$ 0.09920	$ 0.09000
Winter	$ 0.02660	$ 0.02660

(1) Exisiting Summer season is May - October.
Proposed billing units reflects proposed May - August Summer season.

5.2.2 Small General Service Class – Rate 200

The Small General Service Class cost of service indicates a small over recovery of about 4 percent. As a result, we have proposed a lower than system average percentage increase for the first three years and a system average increase in the fourth year. The first year increase target is 5.06 percent. Subsequent year recommended rate increases are 6 percent, 6 percent, and 7 percent in 2011 through 2013, respectively. As with the residential rates the customer charge has been replaced by a Customer Access Charge. As with the residential rate, the customer charge has been set at about 55 percent of the customer costs and rounded to whole dollars. The Customer Access Charge is $25.00 per month.

The facilities demand charge and the base demand charge have been increased to reflect cost of service principles. The energy charge blocks remain the same with an increase in the summer first block and a decrease in the winter first block to recognize the seasonal differences in costs. The second block of the rate increases in both the summer and winter seasons, but maintains a seasonal differential to more closely approximate the marginal cost by season.

For customers without a demand meter the rate is a flat, seasonally differentiated energy charge with a higher summer rate and a lower winter rate. The rate differential is based on the seasonal cost differences.

In designing Rate 200 we have revised the metering adjustment clause to adjust the measured kW and kWh volumes. The existing rates adjusted the total bill, including the ERC and customer charges. We recommend the ERC be applied to the adjusted measured kWh. As such the Service Voltage factors in the existing ERC are no longer needed. The recommended Small General Service rates are shown in Table 5-4.

Table 5-4
Recommended 2010 Small General Service Base Rates

Description	Present Rate	Recommended Rate
200 - Small General Service		
Customer Charge	$ 16.50	$ 25.00
Facilities Demand		
Secondary Service	$ 2.47	$ 2.70
Primary Service	$ 1.29	$ 1.20
Billed Demand		
First 10 kW	$ -	$ -
All Additional kW	$ 6.05	$ 5.47
Energy Charge		
First 3500 kWh		
Summer (May - August)	$ 0.07080	$ 0.07100
Winter	$ 0.07080	$ 0.06100
All Additional kWh		
Summer (May - August)	$ 0.01120	$ 0.02600
Winter	$ 0.01120	$ 0.01600
Metering Adjustment		
Secondary	0.0%	0.0%
Primary	-2.3%	-2.0%
200ND - SGS - Sec Service Non-demand		
Customer Charge	$ 16.50	$ 25.00
Energy Charge		
All kWh		
Summer (May - August)	$ 0.07620	$ 0.08260
Winter	$ 0.07620	$ 0.06760

5.2.3 Medium General Service – Rate 2500

We are recommending a new rate class, Medium General Service. This class will consist of customers with demands from 70 kW to 1,000 kW. These customers are in the existing Large General Service class which currently includes customers with demands from 70 kW to 4000 kW. BPU staff suggested that this demand range was too large to accurately reflect customer service characteristics. The proposed Large General Service class will be defined as customers having demands greater than 1,000 kW up to 4,000 kW.

The cost of service basis for this class is the existing Large General Service Class, which indicates an over recovery in cost of service by about 6 percent. As a result, we have proposed a lower than system average percentage increase for the first three years and a system average increase in the fourth year. The first year increase target for the new Medium and Large General Service Classes combined is 5.06 percent. Subsequent year recommended rate increases are 5 percent, 6 percent, and 7 percent in 2011 through 2013, respectively.

Table 5-5
Recommended 2010 Medium General Service Base Rates

Description	Present LGS Rate	Recommended MGS Rate
250 - Medium General Service		
Customer Charge	$ 38.48	$ 55.00
Facilities Demand		
Secondary Service	$ 2.42	$ 2.77
Primary Service	$ 1.26	$ 1.70
Billed Demand		
All kW	$ 5.77	$ 6.15
Energy Charge		
First 300 kWh per kW		
Summer (May - August)	$ 0.03470	$ 0.04170
Winter	$ 0.03470	$ 0.03170
All Additional kWh		
Summer (May - August)	$ 0.01020	$ 0.01140
Winter	$ 0.01020	$ 0.01020
Metering Adjustment		
Secondary	2.3%	2.0%
Primary	0.0%	0.0%

5.2.4 Large General Service Class – Rate 300

The cost of service considerations for rate design purposes for the new Large General Service Class is based on the existing class results. The existing Large General Service Class cost of service indicates an over recovery in cost of service by about 6 percent. As a result, we have proposed a lower than system average percentage increase for the first three years and a system average increase in the fourth year. The first year increase target is 5.06 percent. Subsequent year recommended rate increases are 5 percent, 6 percent, and 7 percent in 2011 through 2013, respectively. Consistent with other schedules, the customer charge has been replaced with a Customer Access Charge. The Customer Access Charge has been increased to 45 percent of the customer costs. This percentage was based on the fact that the facilities demand charge has been increased as well. Thus the combined charges recover more of the fixed costs in fixed charges.

The increase in the facilities demand charge and the base demand charge are based on cost of service principles and recover the remainder of the allocated rate increase. The energy charges in this schedule now reflect a seasonal differential in the first block and the second block remains the same.

In designing Rate 300 we have revised the metering adjustment clause to adjust the measured kW and kWh volumes. The existing rates adjusted the total bill, including the ERC and customer charges. We recommend the ERC be applied to the adjusted measured kWh. As such the Service Voltage factors in the existing ERC are no longer needed. The recommended Large General Service rates are shown in Table 5-6.

Table 5-6
Recommended 2010 Large General Service Base Rates

Description	Present Rate	Recommended Rate
300 - Large General Service		
Customer Charge	$ 38.48	$ 87.00
Facilities Demand		
Secondary Service	$ 2.42	$ 2.77
Primary Service	$ 1.26	$ 1.70
Billed Demand		
All kW	$ 5.77	$ 6.95
Energy Charge		
First 300 kWh per kW		
Summer (May - August)	$ 0.03470	$ 0.03700
Winter	$ 0.03470	$ 0.02950
All Additional kWh		
Summer (May - August)	$ 0.01020	$ 0.01020
Winter	$ 0.01020	$ 0.01020
Metering Adjustment		
Secondary	2.3%	2.0%
Primary	0.0%	0.0%

5.2.5 Large Power Service Class – Rate 400

The Large Power Service Class cost of service indicates under recovery of cost of service by about 26 percent. As a result, we have proposed a higher than system average percentage increase for the first three years and a system average increase in the fourth year. The first year increase target is 10.4 percent. With rounding of rate elements the actual increase is 10.3 percent. Subsequent year recommended rate increases are 8.75 percent, 8 percent, and 7 percent in 2011 through 2013, respectively. The increase is based on the fact that this class of service exhibited the largest percentage increase to achieve cost of service and thus warranted the largest percentage increase, with the first year target increase just under the class maximum guideline of 10.5 percent.

The increases for this schedule include an increase to the Customer Access Charge, the facilities demand charge and the base demand charge. The proposed energy charges also reflect a seasonal differential, with the summer energy charges remaining the same and the winter energy charges reduced slightly. The facilities charge changes are based on the cost of service with the secondary service charge increasing, the primary service charge decreasing slightly and the substation charge increasing. The base demand charge increased to produce the target revenue.

In designing Rate 400 we have revised the metering adjustment clause to adjust the measured kW and kWh volumes. The existing rates adjusted the total bill, including the ERC and customer charges. We recommend the ERC be applied to the adjusted measured kWh. As such the Service Voltage factors in the existing ERC are no longer needed. The recommended Large Power Service rates are shown in Table 5-7.

Table 5-7
Recommended 2010 Large Power Service Base Rates

Description	Present Rate	Recommended Rate
400 - Large Power Service		
Customer Charge	$ 109.94	$ 173.00
Facilities Demand		
Secondary Service	$ 2.42	$ 2.65
Primary Service	$ 1.26	$ 1.20
Substation Service	$ 0.38	$ 0.84
Billed Demand		
All kW	$ 6.82	$ 7.67
Energy Charge		
First 300 kWh per kW		
Summer (May - August)	$ 0.02030	$ 0.02030
Winter	$ 0.02030	$ 0.01830
All Additional kWh		
Summer (May - August)	$ 0.01010	$ 0.01010
Winter	$ 0.01010	$ 0.00900
Metering Adjustment		
Secondary	2.0%	2.0%
Primary	0.0%	0.0%
Substation	-3.8%	-2.8%
Transmission	-4.3%	-3.3%

5.2.6 Unified School District #500 and Lighting Classes

Both of these classes produce returns in excess of the system average return. Given the level of the excess return and the class revenue level, we propose no increase for these two classes in the first year. In subsequent years, we propose a less than average increase in the second and third year (3 percent and 5 percent, respectively) and an average increase in the fourth year.

5.2.7 Subsequent Year Increases

Table 5-8 presents the recommended base rate increases in 2010 and recommended increases for each rate class for 2011 through 2013. The average increase is 7 percent per year.

Table 5-8
Recommended Rate Class Percentage Increases by Year

Base Rate Summary	2010	2011	2012	2013
Rate 100 – Residential	8.75%	8.75%	8.00%	7.00%
Rate 200 - Small General Service	5.06%	6.00%	6.00%	7.00%
Rate 2500 – Medium General Service	5.06%	5.00%	6.00%	7.00%
Rate 300 - Large General Service	5.06%	5.00%	6.00%	7.00%
Rate 400 - Large Power Service	10.40%	8.75%	8.00%	7.00%
Rate 500 – USD #500	0.00%	3.00%	5.00%	7.00%
Rate 700 – Lighting	0.00%	3.00%	5.00%	7.00%

As the table illustrates, the increases are designed to move the various rate classes toward cost of service over time while avoiding disruptively large increase relative to the average 7 percent increase. In the last year, each class is increased by the average to allow for the system to develop a new cost study at that time to assess the relative returns and the need for further rate adjustments. We propose that there be no rate design change in these years. Rather, the rate increase will be implemented as a percentage surcharge applicable to the base rate bill. The applicable annual surcharges by rate class for 2011 through 2013 are shown in Table 5-9.

Table 5-9
Applied Percentage Surcharges by Year

Base Rate Summary	2011	2012	2013
Rate 100 – Residential	8.75%	17.45%	25.67%
Rate 200 - Small General Service	6.00%	12.36%	20.23%
Rate 2500 - Medium General Service	5.00%	11.30%	19.09%
Rate 300 - Large General Service	5.00%	11.30%	19.09%
Rate 400 - Large Power Service	8.75%	17.45%	25.67%
Rate 500 - USD #500	3.00%	8.15%	15.72%
Rate 700 – Lighting	3.00%	8.15%	15.72%

5.2.8 Energy Rate Component (ERC)

We are recommending several changes in the Energy Rate Component (ERC) to improve the timely recovery of costs. These include:

- Increasing the frequency of the ERC adjustment to a quarterly adjustment with reconciliation adjustments to occur 90 days after the close of the quarter.
- Eliminating the ERC provision related to service voltage adjustment consistent with the metering credit provisions in the recommended base rates .

- Adjusting the Purchase Power definition to include all generation and transmission capacity charges. Additional charges that may be assessed by the Southwest Power Pool and related to transmission, market operations including energy imbalance, day-ahead energy, capacity and ancillary service markets.

5.2.9 Environmental Surcharge (ESC)

We are recommending a new Rider, an Environmental Surcharge (ESC). The purpose of this Rider is to provide for the recovery of the Utility's capital investment in projects not recovered in base rates that are required to meet Federal, state, reliability council, or local environmental regulations. Several future capital intensive projects are being considered by the BPU should the anticipated environmental regulations be mandated. The capital costs of these projects are not included in the recommended base rates.

The ESC will be applicable to all electricity billed to retail customers excluding sales to the Board of Public Utilities (BPU), the portion of Unified Government of Wyandotte County/Kansas City, Kansas belonging to customer class "City of KCK" and contract customers where recovery of a surcharge is not permitted under the terms of a contract. The surcharge is intended to recover only the annual cash expenditures of the Utility, whether in direct expenditures or in the form of debt service payments for Environmental Bonds, until such time costs can be recovered in base rates.

The calculation of the projected ESC shall be made in the fourth quarter of each calendar year and applied to customer bills rendered beginning January 1 of the following calendar year. Based on the current forecast the initial application of the ESC will begin in July 2010, following the issuance of Environmental Bonds. The Utility shall provide annual reports to the Board of its collections including a calculation of the total revenue collected under this Rider.

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 Utility for any dollar amount expended on required environmental capital projects for retail customers. The Environmental Surcharge is expressed in $ per kWh and rounded to the nearest $0.0001. The forecast 2010 surcharge is $0.0005/ kWh applied to all metered usage. The ESC is presented in Appendix A and includes an annual reconciliation adjustment (true up).

5.3 Typical Bill Comparison

Table 5-10 shows a comparison of existing and recommended rates at various usage and demand levels for the Residential and Small General Service rate classes. Table 5-11 shows a comparison of existing and recommended rates at various usage and demand levels for the Medium General Service, Large General Service, and Large Power Service rate classes.

5.4 Other Rate Design Considerations

The BPU is also evaluating the possibility of a Time of Use rate structure and Interruptible and/or Curtailable Service arrangements. Specific rates or riders will not be a part of this rate study, but may be considered on a trial basis, subject to a determination of what is in the best interests of the utility.

Table 5-10
Typical Bill Comparison
Residential and Small General Service Rate Classes

Rate Class	Energy	Facility	Demand	Existing Bill[1]	Recommended Bill[1]	Increase	Increase
	kWh	kW	KW	$	$	$	%
			Monthly				
100 - Residential - Winter	500			46.95	48.45	1.50	3.2%
100 - Residential - Winter	750			67.12	66.55	(0.57)	-0.9%
100 - Residential - Winter	1,000			87.30	84.65	(2.65)	-3.0%
100 - Residential - Winter	1,500			112.80	119.60	6.80	6.0%
100 - Residential - Summer	750			67.12	75.92	8.80	13.1%
100 - Residential - Summer	1,000			87.30	97.15	9.85	11.3%
100 - Residential - Summer	1,500			133.10	144.60	11.50	8.6%
100 - Residential - Summer	2,000			178.89	192.04	13.15	7.4%
100 - Residential - Summer	2,500			240.69	249.49	8.80	3.7%
101 - Residential Electric Heat - Winter	1,000			87.30	84.65	(2.65)	-3.0%
101 - Residential Electric Heat - Winter	1,500			112.80	112.10	(0.70)	-0.6%
101 - Residential Electric Heat - Winter	2,000			138.29	139.54	1.25	0.9%
101 - Residential Electric Heat - Winter	2,500			163.79	165.29	1.50	0.9%
101 - Residential Electric Heat - Summer	750			67.12	75.92	8.80	13.1%
101 - Residential Electric Heat - Summer	1,000			87.30	97.15	9.85	11.3%
101 - Residential Electric Heat - Summer	1,500			133.10	144.60	11.50	8.6%
101 - Residential Electric Heat - Summer	2,000			178.89	192.04	13.15	7.4%
101 - Residential Electric Heat - Summer	2,500			240.69	249.49	8.80	3.7%
200 - SGS - Secondary - Summer	2,500	20	10	364.34	373.44	9.10	2.5%
200 - SGS - Secondary - Summer	3,750	25	15	511.01	522.91	11.90	2.3%
200 - SGS - Secondary - Summer	6,000	30	20	633.66	678.28	44.63	7.0%
200 - SGS - Secondary - Summer	7,500	35	25	729.62	795.48	65.86	9.0%
200 - SGS - Secondary - Summer	12,000	60	40	1,042.21	1,174.06	131.85	12.7%
200 - SGS - Secondary - Summer	16,500	70	55	1,317.75	1,512.15	194.40	14.8%
200 - SGS - Secondary - Winter	2,500	20	10	364.34	348.44	(15.90)	-4.4%
200 - SGS - Secondary - Winter	3,750	25	15	511.01	485.41	(25.60)	-5.0%
200 - SGS - Secondary - Winter	6,000	30	20	633.66	618.28	(15.37)	-2.4%
200 - SGS - Secondary - Winter	7,500	35	25	729.62	720.48	(9.14)	-1.3%
200 - SGS - Secondary - Winter	12,000	60	40	1,042.21	1,054.06	11.85	1.1%
200 - SGS - Secondary - Winter	16,500	70	55	1,317.75	1,347.15	29.40	2.2%

(1) Monthly bill calculations include ERC Rider and ESC Rider, but no PILOT or taxes

Table 5-11
Typical Bill Comparison
Medium General Service, Large General Service, and Large Power Service Rate Classes

Rate Class	Energy	Facility	Demand	Existing Bill[1]	Recommended Bill[1]	Recommended Increase	Recommended Increase
	kWh	kW	KW	$	$	$	%
		Monthly					
2500 - MGS - Secondary - Summer	35,000	150	100	3,005.31	3,329.09	323.78	10.8%
2500 - MGS - Secondary - Summer	75,000	300	200	6,150.18	6,788.30	638.12	10.4%
2500 - MGS - Secondary - Summer	125,000	500	300	9,776.66	10,759.01	982.34	10.0%
2500 - MGS - Secondary - Summer	175,000	700	450	14,074.23	15,506.95	1,432.72	10.2%
2500 - MGS - Secondary - Winter	35,000	150	100	3,005.31	3,016.97	11.66	0.4%
2500 - MGS - Secondary - Winter	75,000	300	200	6,150.18	6,157.94	7.76	0.1%
2500 - MGS - Secondary - Winter	125,000	500	300	9,776.66	9,798.17	21.50	0.2%
2500 - MGS - Secondary - Winter	175,000	700	450	14,074.23	14,080.99	6.76	0.0%
300 - LGS - Secondary - Summer	400,000	1,500	1,000	31,488.02	33,934.48	2,446.45	7.8%
300 - LGS - Secondary - Summer	600,000	2,000	1,500	46,593.44	50,151.86	3,558.43	7.6%
300 - LGS - Secondary - Summer	800,000	2,500	2,000	61,698.85	66,369.25	4,670.40	7.6%
300 - LGS - Secondary - Winter	400,000	1,500	1,000	31,488.02	31,639.48	151.45	0.5%
300 - LGS - Secondary - Winter	600,000	2,000	1,500	46,593.44	46,709.36	115.93	0.2%
300 - LGS - Secondary - Winter	800,000	2,500	2,000	61,698.85	61,779.25	80.40	0.1%
300 - LGS - Primary - Summer	800,000	2,750	2,000	57,726.68	62,819.60	5,092.92	8.8%
300 - LGS - Primary - Summer	1,200,000	4,000	3,000	86,413.28	93,973.40	7,560.12	8.7%
300 - LGS - Primary - Summer	1,600,000	5,500	4,000	115,414.88	125,552.20	10,137.32	8.8%
300 - LGS - Primary - Winter	800,000	2,750	2,000	57,726.68	58,319.60	592.92	1.0%
300 - LGS - Primary - Winter	1,200,000	4,000	3,000	86,413.28	87,223.40	810.12	0.9%
300 - LGS - Primary - Winter	1,600,000	5,500	4,000	115,414.88	116,552.20	1,137.32	1.0%
400 - LPS - Secondary - Summer	1,000,000	3,500	2,500	69,040.68	72,691.94	3,651.26	5.3%
400 - LPS - Secondary - Summer	1,200,000	4,000	3,000	82,332.71	86,655.13	4,322.42	5.2%
400 - LPS - Secondary - Summer	1,400,000	4,750	3,500	96,241.83	101,294.07	5,052.23	5.2%
400 - LPS - Secondary - Winter	1,000,000	3,500	2,500	69,040.68	70,881.44	1,840.76	2.7%
400 - LPS - Secondary - Winter	1,200,000	4,000	3,000	82,332.71	84,482.53	2,149.82	2.6%
400 - LPS - Secondary - Winter	1,400,000	4,750	3,500	96,241.83	98,759.37	2,517.53	2.6%
400 - LPS - Primary - Summer	1,400,000	5,000	3,500	89,159.74	92,723.80	3,564.06	4.0%
400 - LPS - Primary - Summer	2,000,000	8,000	5,000	128,403.94	133,417.00	5,013.06	3.9%
400 - LPS - Primary - Summer	2,800,000	10,000	7,000	178,209.54	185,274.60	7,065.06	4.0%
400 - LPS - Primary - Winter	1,400,000	5,000	3,500	89,159.74	90,238.80	1,079.06	1.2%
400 - LPS - Primary - Winter	2,000,000	8,000	5,000	128,403.94	129,867.00	1,463.06	1.1%
400 - LPS - Primary - Winter	2,800,000	10,000	7,000	178,209.54	180,304.60	2,095.06	1.2%
400 - LPS - Substation - Summer	6,000,000	15,000	12,000	318,241.09	341,677.42	23,436.34	7.4%
400 - LPS - Substation - Summer	8,000,000	20,000	16,000	424,286.19	455,512.23	31,226.04	7.4%
400 - LPS - Substation - Summer	10,000,000	25,000	20,000	530,331.30	569,347.04	39,015.74	7.4%
400 - LPS - Substation - Winter	6,000,000	15,000	12,000	318,241.09	332,112.94	13,871.86	4.4%
400 - LPS - Substation - Winter	8,000,000	20,000	16,000	424,286.19	442,759.59	18,473.40	4.4%
400 - LPS - Substation - Winter	10,000,000	25,000	20,000	530,331.30	553,406.24	23,074.94	4.4%

(1) Monthly bill calculations include ERC Rider and ESC Rider, but no PILOT or taxes

APPENDIX A – RATE MANUAL

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 five 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 electric and water rate schedules for the BPU under which customers may be served. Sections IV and V 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 and V 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.

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.

COMMERCIAL USE: Commercial use is defined as non-residential consumption which is not primarily and directly used in the creation of a product, delivery of a service, or used in one of the primary industries.

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 Access Charge for billing purposes.

CUSTOMER ACCESS CHARGE: A Customer Access 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 Access 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. For bills under 24 days, the Customer Access Charge will not be prorated. For bills longer than 36 days the Customer Access Charge shall be prorated based on 30 day intervals or portion thereof.

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. In the event that a bill is rendered for more than 36 days, the demand charge but not the billing demand shall be prorated.

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.

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 Facilities Demand.

HOLIDAYS: The following days:

1. New Year’s Day
2. Martin Luther King’s Day
3. President’s Day
4. Good Friday
5. Memorial Day
6. Independence Day
7. Labor Day
8. Thanksgiving
9. Day After Thanksgiving
10. Christmas Day

INDUSTRIAL USE: Industrial use is defined as non-residential use wherein the primary use of the commodity is in the fabrication of a product or use in a primary industry.

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.

MILL: A Mill is one thousandth of a dollar ($0.001). It has value in expressing small numbers in that it reduces the need to use zeroes.

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.

RESIDENTIAL: Residential use is defined as use in a dwelling or in a facility where the primary nature of the facility is that of a residence or dwelling where not more than 25 KVA of installed or allocated transformer capacity is required. Where more than 25 KVA of installed or allocated transformer capacity is required, the Small General Service Rate Schedule shall apply. Multi-family dwellings are considered residences when billed as individual units, otherwise the facility is considered commercial.

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.

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

SUMMER: Summer is defined as the four months May through August. For cycle billed customers, the summer is defined as the four consecutive cycles billed after May 15.

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.

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:

	Summer	Winter
CUSTOMER ACCESS CHARGE	$ 12.25	$12.25 Per Billing Cycle

ENERGY CHARGE	Summer	Winter	
First 1,000 kWh…………………….….	$0.0600	$0.0475	Per kWh
Next 1,000 kWh.……………………	$0.0700	$0.0450	Per kWh
All Additional kWh…………………	$0.0900	$0.0450	Per kWh

MINIMUM BILL:
The Monthly Customer Access Charge.

APPLICABLE RIDERS:
E1 Energy Rate Component Rider (Page 20)
E2 Payment-In-Lieu-Of-Tax (Page 23)
E16 Electric Rate Stabilization Rider (Page 25)
E17 Environmental Surcharge Rider (Page 27)

Rate Code: 100
Effective: XX-01-10
Supersedes Rate Effective: 1-1-07

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

APPLICATION:
For residential service to single family residences or individually metered residential dwellings using electric heat as the primary source of heating.

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

2. Electric heating equipment shall be of at least 2.5 kW, single phase, 60 hertz, at available voltage, and not connected through a separately metered circuit. The single phase, alternating current, electric service will be supplied at BPU's standard voltages of 240 volts or less, for residential uses, when all electric service furnished under this Schedule is measured by one meter.

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

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 101:

	Summer	Winter	
CUSTOMER ACCESS CHARGE	$ 12.25	$12.25	Per Billing Cycle

ENERGY CHARGE	Summer	Winter	
First 1,000 kWh…………………….….	$0.0600	$0.0475	Per kWh
Next 1,000 kWh.……………………	$0.0700	$0.0300	Per kWh
All Additional kWh…………………	$0.0900	$0.0266	Per kWh

MINIMUM BILL:
The Monthly Customer Access Charge.

APPLICABLE RIDERS:

E1 Energy Rate Component Rider (Page 20)
E2 Payment-In-Lieu-Of-Tax (Page 23)
E16 Electric Rate Stabilization Rider (Page 25)
E17 Environmental Surcharge Rider (Page 27)

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:

CUSTOMER ACCESS CHARGE .... $25.00 PER Billing Cycle

a) For Customers with Demand Meter

FACILITIES CHARGE

SECONDARY SERVICE……………..	$2.70 PER kW		
PRIMARY SERVICE…………………	$1.20 PER kW		

DEMAND CHARGE

FIRST 10 kW	NO CHARGE		
ALL ADDITIONAL kW……………..	$5.47 PER kW		

ENERGY CHARGE	Summer	Winter	
FIRST 3,500 kWh.............................	$ 0.0710	$0.0610	PER kWh
ALL ADDITIONAL kWh…………	$ 0.0260	$0.0160	PER kWh

b) For Customers without Demand Meter

	Summer	Winter	
All kWh.............................	$ 0.0826	$0.0676	PER kWh

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

DEMAND METERING REQUIREMENT: In the event that a customer uses more than 3,600 kWh for any two consecutive billing periods, a demand meter shall 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 demand occurring in the current month or the preceding 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 May through August shall be the greatest average metered kilowatt demand measured in any 30-minute period during the month. Where time-of-use metering equipment has been installed at customer's expense, the billing demand shall be the greatest average kilowatt demand measured in any 30-minute period between the hours of 10:00 a.m. and 11:00 p.m., excluding weekends and Holidays. The billing demand during the winter period shall be the larger of the maximum demand in 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 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.

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

APPLICABLE RIDERS:

E1 Energy Rate Component Rider (Page 20)
E2 Payment-In-Lieu-Of-Tax (Page 23)
E7 Reactive Adjustment (Page 24)
E16 Electric Rate Stabilization Rider (Page 25)
E17 Environmental Surcharge Rider (Page 27)

Rate Code: 200
Effective: XX-01-10
Supersedes Rate Effective: 1-1-07

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:

CUSTOMER ACCESS CHARGE		$55.00 PER Billing Cycle
FACILITIES CHARGE		
SECONDARY SERVICE…………….		$2.77 PER kW
PRIMARY SERVICE…………………		$1.70 PER kW
DEMAND CHARGE		$6.15 PER kW
ENERGY CHARGE	Summer	Winter
FIRST 300 kWh PER kW…………	$0.0417	$0.0317 per kWh
ALL ADDITIONAL ENERGY…	$0.0114	$0.0102 per kWh

MINIMUM BILL:
The Monthly Customer Access 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 demand occurring in the current month or the preceding 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 May through August 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. Where time-of-use metering equipment has been installed at customer's expense, the billing demand shall be the greatest average kilowatt demand measured in any 30-minute period between the hours of 10:00 a.m. and 11:00 p.m., excluding weekends and Holidays. The billing demand during the winter period shall be the greater of the maximum demand in 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%

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.

APPLICABLE RIDERS:

E1 Energy Rate Component Rider (Page 20)
E2 Payment-In-Lieu-Of-Tax (Page 23)
E7 Reactive Adjustment (Page 24)
E16 Electric Rate Stabilization Rider (Page 25)
E17 Environmental Surcharge Rider (Page 27)

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:

CUSTOMER ACCESS CHARGE		$87.00 PER Billing Cycle
FACILITIES CHARGE		
SECONDARY SERVICE…………….		$2.77 PER kW
PRIMARY SERVICE…………………		$1.70 PER kW
DEMAND CHARGE		$6.95 PER kW
ENERGY CHARGE	Summer	Winter
FIRST 300 kWh PER kW…………	$0.0370	$0.0295 per kWh
ALL ADDITIONAL ENERGY	$0.0102	$0.0102 per kWh

MINIMUM BILL:
The Monthly Customer Access 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 demand occurring in the current month or the preceding 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 May through August 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. Where time-of-use metering equipment has been installed at customer's expense, the billing demand shall be the greatest average kilowatt demand measured in any 30-minute period between the hours of 10:00 a.m. and 11:00 p.m., excluding weekends and Holidays. The billing demand during the winter period shall be the greater of the maximum demand in 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%

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.

APPLICABLE RIDERS:

E1 Energy Rate Component Rider (Page 20)
E2 Payment-In-Lieu-Of-Tax (Page 23)
E7 Reactive Adjustment (Page 24)
E16 Electric Rate Stabilization Rider (Page 25)
E17 Environmental Surcharge Rider (Page 27)

Rate Code: 300
Effective: XX-01-10
Supersedes Rate Effective: 01-01-07

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:

CUSTOMER ACCESS CHARGE	$173.00 PER Billing Cycle	
FACILITIES CHARGE		
SECONDARY SERVICE…………….	$2.65 PER kW	
PRIMARY SERVICE…………………	$1.20 PER kW	
SUBSTATION SERVICE…………….	$0.84 PER kW	
DEMAND CHARGE	$7.67 PER kW	
ENERGY CHARGE	Summer	Winter
FIRST 300 kWh PER kW…………	$0.0203	$0.0183 per kWh
ALL ADDITIONAL ENERGY	$0.0101	$0.0090 per kWh

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

FACILITIES DEMAND:
The Facilities demand shall be equal to the highest metered demand occurring in the current month or the preceding eleven 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 May through August shall be the larger of the contract demand (as mutually agreed upon) or the greatest average kilowatt demand measured in any thirty minute period between the hours of 10:00 a.m. and 11:00 p.m., excluding weekends and holidays. The billing demand during the winter period of the year shall be the greater of the maximum demand in 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%
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.

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

APPLICABLE RIDERS:
E1 Energy Rate Component Rider (Page 20)
E2 Payment-In-Lieu-Of-Tax (Page 23)
E7 Reactive Adjustment (Page 24)
E16 Electric Rate Stabilization Rider (Page 25)
E17 Environmental Surcharge Rider (Page 27)

Rate Code: 400
Effective: XX-01-10
Supersedes Rate Effective: 1-1-07

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:
The Company will install, own and operate the following items designated as standard equipment:

MONTHLY RATE:

1. Private Area Lighting	**Monthly Charge**	**Estimated Monthly kWh**	**Rate Code**
175 Watt Mercury Vapor*..	$13.35	63	701
400 Watt Mercury Vapor*..	$20.04	151	702
400 Watt Mercury Vapor (Power Flood)*.................	$23.75	151	703
1,000 Watt Mercury Vapor*.......................................	$41.02	361	704
1,000 Watt Mercury Vapor (Power Flood)*................	$48.40	361	705
70 Watt High Pressure Sodium.................................	$13.99	25	706
250 Watt High Pressure Sodium...............................	$16.11	104	707
250 Watt High Pressure Sodium (Power Flood)........	$24.47	104	708
400 Watt High Pressure Sodium...............................	$44.32	151	709
400 Watt High Pressure Sodium (Power Flood)........	$51.73	151	710
70 Watt High Pressure Sodium (Power Flood)..........	$20.11	25	711

* New installations of the following shall no longer be available on and after December 29, 1998. The decision to repair or replace these installations with another type shall be Company's option.

Additional Facilities:

35 Foot Wooden Pole	$5.10	730
26 Foot Steel Pole and Base	$11.64	731

Additional Span of Wire (170 Ft. Max)	$1.13	732

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
Private Lighting	9.9627 cents per kWh	750
Municipal Lighting	8.4973 cents per kWh	751
Kansas Department of Transportation	8.4973 cents per kWh	752

3. Traffic and Railroad Signal:

		Rate Code
Railroad Warning Lights	$2.75 per service	760

APPLICABLE RIDERS:

E1 Energy Rate Component (##)
E2 Payment-In-Lieu-Of-Tax (##)
E16 Electric Rate Stabilization Rider (##)
E # Environmental Surcharge Rider (#)

Rate Code: 700 through 710 and 750 through 760
Effective: XX-01-10
Supersedes Rate Effective: 1-1-07

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 retail 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:

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

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.

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) fossil fuel costs (which includes all energy-related costs incurred by reason of using fossil fuel), (ii) purchased power energy-related costs, (iii) all energy-related transmission charges, (iv) purchased power and transmission demand and capacity costs, (v) all market participation related costs, and (vi) all energy efficiency and demand response costs which give the utility direct control of customer load for peak shaving, not otherwise recovered, less (b) the sum of: (i) cost of fuel and purchased power recovered through all inter-system sales of energy and (ii) the net value of Renewable Energy Certificates (REC) sold in the market, 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.

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

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 Certificates (REC), are tradable, intangible energy commodities in the United States that represent proof that 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.

Effective: XX-01-10
Supersedes Rider E1 Effective: 11-1-03

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 in 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. On January 1, 2010, this rate was 12.8%. 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 then 5 percent and no more then 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.

Effective: 2-1-02
Supersedes Rider E2 Effective: 2-1-98

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 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 don't 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.

Effective: 7-1-10
Supersedes Rider E7 Effective: 11-1-03

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

Effective: 1-1-07
Supersedes Rider E16 Effective: 7-1-02

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.

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.

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Effective: 1-1-07
Supersedes Rider E16 Effective: 7-1-02

PURPOSE:
The purpose of this Rider is to provide for the recovery of the Utility's capital investment in projects that are required to meet Federal, State or Local environmental regulations.

APPLICABILITY:
Applicable to all retail electricity 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 for retail customers.

AMOUNT:
The amount of Environmental Surcharge (ESC) to be paid on electricity delivered to retail customers shall be calculated as follows:

ESC = (ECC + RA) / S

Where:
ESC = Environmental Surcharge expressed in $ per kWh and rounded to the nearest $0.0001.

ECC = Environmental Capital-related Costs for the projected calendar year, expressed in dollars, not recovered through the application of a rate schedule or rider or through other means such as reimbursement through government assistance. Environmental capital related costs shall be the sum of: (i) that portion of material cash expenditures on environmental capital projects not debt financed which are to be recovered in the projected calendar year as described herein, plus (ii) debt service payments (principal plus interest) in the projected calendar year on environmental capital projects which are or projected to be debt financed, less (iii) cash expenditures or debt service payments on environmental capital projects that are projected to be recovered from Participation or other non-retail customers in the projected calendar year. Cash expenditures on environmental capital projects will be considered material if the combined amount for all projects within the year equals or exceeds $1,000,000. Material cash expenditures included in an application of this rider may include projected cash expenditures for the projected calendar year, subject to reconciliation of projected to actual expenditures at the end of the calendar year, and material cash expenditures previously incurred which have not been recovered under this rider or otherwise. Recovery of material cash expenditures may be amortized over more than one year.

RA = Reconciliation Adjustment expressed in dollars. The projected ESC revenue for the most recent prior 12 month period for which billing data is available, less the actual ESC revenue billed for the same period.

S = Sales of electricity to retail customers, expressed in kilowatt hours, (kWh) forecast for the projected calendar year. Projected sales of electricity to retail customers shall exclude usage by the Board of Public Utilities (BPU) and the portion of Unified Government of Wyandotte County/Kansas City, Kansas belonging to customer class “City, of KCK” and sales to contract customers where recovery of the ESC is not permitted under the terms of the contract.

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

Effective: XX-01-10