STATE OF KANSAS

BEFORE THE KANSAS CORPORATION COMMISSION

Application for Revised Rates, Tariffs, and Rate Design Changes

of

Mid-Kansas Electric Company, LLC

Docket No. 10-MKEE-439-RTS

December 8, 2010

PREFILED DIRECT TESTIMONY
RICHARD J. MACKE
VICE PRESIDENT, RATES AND FINANCIAL PLANNING
POWER SYSTEM ENGINEERING, INC.

ON BEHALF OF
MID-KANSAS ELECTRIC COMPANY, LLC

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PART I - QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Richard J. Macke. My business address is 10710 Town Square Drive NE, Suite 201, Minneapolis, Minnesota 55449.

Q. What is your profession?

A. I am a Vice President and lead the Rates and Financial Planning Department at Power System Engineering, Inc. ("PSE"), which is headquartered at 1532 W. Broadway, Madison, Wisconsin 53713.

Q. Please describe the business activities of PSE.

A. Power System Engineering, Inc. is a consulting firm serving electric utilities across the country, but primarily in the Midwest. Our headquarters are in Madison, Wisconsin with regional offices in Indianapolis, Indiana; Minneapolis, Minnesota; Marietta, Ohio; and Sioux Falls, South Dakota. PSE is involved in: power supply, transmission and distribution system planning; distribution, substation and transmission design; construction contracting and supervision; retail and wholesale rate and cost of service ("COS") studies; economic feasibility studies; merger and acquisition feasibility analysis; load forecasting; financial and operating consultation; telecommunication and network design, mapping/GIS; and system automation including Supervisory Control and Data Acquisition ("SCADA"), Demand Side Management ("DSM"), metering, and outage management systems.

Q. Please describe your responsibilities with PSE.

A. I lead and direct staff in both Minnesota and Indiana who provide financial and rate-related consulting services predominantly to electric cooperative and municipal utilities. These services include:

- Cost of Service Studies;
- Retail Rate Design and Analysis;
- Load Management Analysis;
- Individual Customer Profitability;
- Financial Forecasting;
- Capital Credit Allocations;
- Special Fees and Charges;
- Line Extension Policies/Charges;
- Large Power Contract Rates/Proposals;
- Merger Analysis;
- Rate Consolidation;
- Pole Attachment Charges;
- Distributed Generation Rates; and
- Power Cost Adjustments.

Q. What is your educational background?

A. I graduated from Bethel University in St. Paul, Minnesota in 1996 with a Bachelor of Arts degree in Business, which included an emphasis in Finance and Marketing. In 2007, I received my Masters of Business Administration degree, with an emphasis in Finance and Strategic Management, from the University of Minnesota in Minneapolis, Minnesota.

Q. What is your professional background?

A. From 1996 to 1998, I was employed by PSE in its Blaine, Minnesota office as a Financial Analyst in the Utility Planning and Rates Department. My work responsibilities primarily were focused on retail rate studies, including revenue requirements and bundled/unbundled COS studies. I also provided analysis used to support testimony, mergers and acquisitions analysis and financial forecasting.

From 1998 to 1999, I was employed as a Senior Analyst by Energy & Resource Consulting Group, LLC in Denver, Colorado, a financial, engineering and management consulting firm. I performed consulting services related to electric, gas and water rate studies. As part of the Legend Consulting Advisor Team contracted to the City Council of the City of New Orleans, Louisiana, I assisted in various electric and gas utility matters. I also provided general financial, management and public policy support to clients.

I rejoined PSE in 1999; and from 1999 to 2002, I held the position of Rate and Financial Analyst in the Rates and Financial Planning Department. From 2002 to March 2008, I held the position of Senior Rate and Financial Analyst in the Utility Planning and Rate Division. My responsibilities have included performing complex financial analyses, such as rate studies consisting of determination of revenue requirements, bundled and unbundled COS analysis, and rate design. Other responsibilities included performing analysis of special rates and programs, key account analyses, financial forecasting, merger and acquisition analysis, activity-based costing, policy development and evaluation, and other financial analyses for various PSE clients. Additional responsibilities included strategic planning, litigation support, regulatory compliance, capital expenditure and operational assessments and advisement. From April 2008 to June 2010, I held the position of Leader, Rates and Financial Planning. Since July 2010, I have held the position of Vice President, Rates and Financial Planning. In this capacity, I continue to provide, amongst other things: 1) rate, financial and economic consulting services to clients, 2) management and leadership to the Rates and Financial Planning Department, and 3) management and leadership at the corporate level to PSE through participation on the Executive Committee and Board of Directors.

Q. Have you previously presented testimony before the Kansas Corporation Commission ("KCC" or "Commission") relative to rate change applications?

A. Yes. I submitted testimony on behalf of: Pioneer Electric Cooperative, Inc. in Docket No. 09-PNRE-563-RTS; Wheatland Electric Cooperative, Inc. in Docket No. 09-WHLE-681-RTS; and Mid-Kansas Electric Company, LLC in Docket No. 09-MKEE-969-RTS.

Q. Do you have any other rate-related experience?

A. Yes. I have directed well over 100 rate and COS studies and numerous other rate and financial related projects. Many times these projects were conducted for self-regulated electric utilities. I have also performed such analysis, which was filed in regulated rate cases, on behalf of cooperatives in Iowa, Kansas, Michigan, Minnesota and New Hampshire.

I have also conducted seminars and made presentations to utilities, consumers and industry groups on a variety of topics, including: COS, rate change communications, line extension policies, mergers and acquisitions, DSM, conservation and energy efficiency, industry trends and rate design strategic planning.

PART II - INTRODUCTION

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

A. The purpose of my testimony is to present my analysis of Mid-Kansas Electric Company, LLC's ("Mid-Kansas") retail revenue requirements, class cost of service ("COS") study and proposed rates for the Wheatland Electric Cooperative, Inc. ("Wheatland") division.

Q. Please describe Mid-Kansas' Wheatland division.

A. It is the Aquila, Inc. ("Aquila") electric system that was acquired by Mid-Kansas, which is served in part under contracts with its six distribution Member-System owners. The Wheatland division refers to the area acquired by Mid-Kansas and that is served at the distribution level by Wheatland. My testimony and analysis is structured around evaluating retail rates and costs for service of customers in the geographical area of Mid-Kansas' certificated territory served by Wheatland given the unique characteristics of that portion of the acquired area.

Q. Did you previously provide testimony supporting the changing of retail rates for the other Mid-Kansas divisions?

A. Yes. In Docket No. 09-MKEE-969-RTS ("Docket 969"), I provided testimony supporting retail rates for the other Mid-Kansas divisions. The other Mid-Kansas Member-System owners are as follows:

- Lane-Scott Electric Cooperative, Inc. ("Lane-Scott");
- Prairie Land Electric Cooperative, Inc. ("Prairie Land");
- Southern Pioneer Electric Company, Inc. ("Southern Pioneer");
- Victory Electric Cooperative Association, Inc. ("Victory"); and
- Western Cooperative Electric Association, Inc. ("Western").

Q. What are Mid-Kansas' objectives in filing this rate application?

A. Mid-Kansas has three primary objectives in filing this rate application. The first objective is to continue the process toward the ultimate goal of transferring the certificated territory to each of the Member-Systems. The distribution facilities, including the 34.5 kV facilities, were transferred to the Member-Systems on December 31, 2007. In order for the transfer of the retail consumers and certificated territory to take place, it is necessary to establish retail rates that reflect the cost of service for each Member-System's assigned service area.

The second objective is financial. The cost of serving the subject areas has risen since the last rate change, which became effective on March 30, 2005, based upon a 2004 Test Year (Docket No. 04-AQLE-1065-RTS). The cost increases since the last rate case make an increase in rates necessary and unavoidable; and this rate application will allow Mid-Kansas to receive an increase in operating revenues needed to achieve acceptable financial operating results.

The third objective of this rate application is to modify rate design to ensure fair and equitable recovery of costs by rate class and rate components. The 2005 rate application by Aquila did not include a class COS study, a fact which concerned Commission Staff and which the Commission stated was problematic (Commission Order, Docket No. 04-AQLE-1065-RTS, page 43, paragraph 131). A new class COS study has been completed and is being submitted by Mid-Kansas for the Wheatland division. Using the COS study results in determining the proposed rate design will ensure that cost recovery is achieved in a way that is fair and equitable between and within the various rate classes.

Q. Are you sponsoring any exhibits?

A. Yes. I have included the following exhibits detailing the analysis completed:

Exhibit __(RJM-WH-1)	-	Curriculum Vitae - Richard J. Macke.
Exhibit __(RJM-WH-2)	-	Statement of Operations - Present Rates.
Exhibit __(RJM-WH-3)	-	Revenue Requirements.
Exhibit __(RJM-WH-4)	-	Cost of Service Analysis.
Exhibit __(RJM-WH-5)	-	Local Access Charge Cost of Service Analysis.
Exhibit __(RJM-WH-6)	-	Proposed Rate Increase Phase In.
Exhibit __(RJM-WH-7)	-	Statement of Operations - Proposed Rates.
Exhibit __(RJM-WH-8)	-	Summary of Consumers, Energy Sales and Revenue - Proposed Rates Phase 1
Exhibit __(RJM-WH-9)	-	Comparison of Present and Proposed Rate Schedules Phase 1.
Exhibit __(RJM-WH-10)	-	Summary of Consumers, Energy Sales and Revenue - Proposed Rates Phase 2
Exhibit __(RJM-WH-11)	-	Comparison of Present and Proposed Rate Schedules Phase 2.
Exhibit __(RJM-WH-12)	-	Calculation of ECA Base.
Exhibit __(RJM-WH-13)	-	Present Rate Schedules.
Exhibit __(RJM-WH-14)	-	Present Rate Schedules with Redline Proposed Changes.
Exhibit __(RJM-WH-15)	-	Proposed Rate Schedules.

Q. Have the exhibits been prepared by you or by others under your supervision?

A. Yes.

PART III - SUMMARY OF DIRECT TESTIMONY

Q. Please summarize the increase being requested for the Wheatland division.

A. A rate increase of $4,264,081 or 19.4 percent is being requested for the Wheatland division.

Q. Please summarize the revenue requirements analysis you prepared for the Wheatland division.

A. With Pro Forma Test Year Operating Expenses of $23,284,752 and Long-Term ("LT") Interest and net Margin Requirements of $3,180,990, the total Pro Forma Test Year Revenue Requirements are calculated to be $26,465,742. Operating Revenue under present rates on a Pro Forma Test Year basis is determined to be $22,198,091. To achieve the targeted Times Interest Earned Ratio ("TIER") of 2.00, revenue must be increased by $4,267,651. Expressed as a percentage of tariff revenue, this is equivalent to a 19.45 percent increase requirement. Table 1 presents a summary of revenue requirements analysis for the Test Year.

Table 1
Wheatland Division
Revenue Requirements Summary
TIER = 2.00 Objective

			($)
1.	Operating Expenses (Excluding Interest)		23,284,752
2.	Margin Requirements		
	a. Interest Expense		1,762,127
	b. Target TIER		2.00
	c. Total Margin Requirements (Before Interest)		3,524,255
	d. Less: Capital Credits		-
	e. Less: Non-Operating Income		343,265
	f. Net Operating Income Required		3,180,990
3.	Total Revenue Requirements		26,465,742
4.	Revenue From Present Rates		
	a. Tariff Revenue		21,943,468
	b. Other Operating Revenue		254,623
	c. Total Revenue		22,198,091
5.	Required Increase (Decrease)		4,267,651
		or	19.45%

Q. Please summarize the results of the COS study you performed for Mid-Kansas for the Wheatland division.

A. The following Table 2 provides a comparison of the calculated cost of providing service to each retail rate class with the revenue generated under the present rates by that class.

Table 2
Wheatland Division
Cost of Service Summary

Rate Class	Revenue Present Rates[1]	Revenue Requirement	Increase (Decrease) Amount	Increase (Decrease) Percent[2]
	($)	($)	($)	(%)
Residential (04-RS)	10,464,800	12,626,046	2,161,245	20.9
GS Small (04-GSS)	939,173	1,281,201	342,028	36.9
GS Small W/Space Heat (04-Rider 1)	27,743	61,654	33,911	123.7
GS Large (04-GSL)	8,428,985	9,892,594	1,463,609	17.6
GS Large W/Space Heat (04-Rider 1)	285,866	383,483	97,617	34.6
Industrial (04-IS)	440,461	518,902	78,441	18.0
Municipal Power (04-M-I)	11,475	17,963	6,488	57.2
Water Pumping (04-WP)	91,057	120,106	29,049	32.3
Irrigation (04-IP-I)	45,604	47,821	2,217	4.9
Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)	559,168	560,177	1,009	0.2
Total[3]	21,294,333	25,509,948	4,215,615	19.8

The above table summarizes the COS study prepared for retail customers. A separate COS was prepared to evaluate the cost of providing local access delivery service for wholesale customers.

Q. Please describe your rate change proposal?

A. Mid-Kansas is proposing a two-phase approach to achieve the overall increase request for the Wheatland division. Phase 1 would be effective with the Commission order, and Phase 2 would be effective one year later. The rate increase requested is as follows:

Phase 1 increase:	$2,384,968 or 10.9 percent
Phase 2 increase:	$1,879,113 or 7.7 percent (incremental)[4]
Total increase:	$4,264,081 or 19.4 percent

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1 Includes an allocated share of Other Operating Revenue.

2 Percentage is calculated using only rate schedule revenue (excludes Other Operating Revenue).

3 The class COS excludes rate classes or consumers which are served under non-standard rates. Also excluded is the Local Access Charge category as that was evaluated separately.

4 The Phase 2 percentage increase is expressed as the incremental increase over Phase 1 rates.

PART IV - REVENUE REQUIREMENTS

Q. Please provide an overview of the revenue requirements analysis.

A. In order to ensure financial viability, a utility's retail rates must be designed to generate sufficient revenue to meet operating expenses and margin requirements. The margin requirements must be adequate to cover interest expense and accomplish other capital management objectives such as rotating patronage capital and maintaining (or achieving) a desired equity position. In this testimony I will refer to the total operating expense and margin requirements as the "revenue requirements." This is expressed by the following equation:

REVENUE REQUIREMENTS = OPERATING EXPENSE + MARGIN REQUIREMENTS

To evaluate a utility's revenue requirements and the adequacy of its present rate structure to meet these requirements, it is common practice to analyze revenue and costs for a 12-month period of time, commonly referred to as the "Pro Forma Test Year" or simply "Test Year."

Q. What Test Year did you use to establish the revenue requirements?

A. The Test Year revenue requirements were based on actual historical results for 12 months ending December 2009, adjusted for known and measurable changes that either occurred during the historical period or within a reasonable time thereafter.

Q. Please describe the revenue requirements analysis you completed for the Wheatland division.

A. Exhibit __(RJM-WH-2) provides a Statement of Operations for the Test Year based on the revenue generated by the present rates. This provides much of the framework for the revenue requirements determination.

Page 1 of Exhibit __(RJM-WH-2) provides a summary of the Statement of Operations for the 2009 Historical Test Year period. The results shown in Column (c) reflect an unadjusted Test Year as actually recorded on Wheatland's books. Column (d) summarizes the various adjustments for known and measurable changes to the revenue and expense accounts with the resulting adjusted Pro Forma Test Year shown in Column (e).

Page 2 of Exhibit __(RJM-WH-2) provides a summary of each of the proposed adjustments. Pages 4 through 22 of Exhibit __(RJM-WH-2) provide the detailed calculations for the adjustments, including:

- Revenue;
- Purchased Power Expense;
- Payroll Expense;
- Payroll Related Expense;
- Depreciation Expense;
- Interest on Long-Term Debt Expense;
- Rate Case Expense;
- Property Tax Expense; and
- Non-Operating Income.

Pages 3 and 4 of Exhibit __(RJM-WH-2) present the average number of consumers, energy sales, billing demand and revenue for the rate classes as recorded for the Historical and the Pro Forma Test Year.

Pages 5 through 8 of Exhibit __(RJM-WH-2) present the calculation of revenue under present rates for the Pro Forma Test Year. Pro Forma Test Year number of consumers, energy sales and billing demand (page 5) are multiplied by appropriate rate schedules to determine the class and system revenue for the Pro Forma Test Year. These revenue calculations are based on the rates currently in effect.

Q. To calculate the adjustment to revenue under present rates, how were the pro forma billing determinants determined?

A. The revenue adjustment reflects the difference between the historical recorded revenue and the pro forma test year revenue as calculated using the pro forma billing determinants contained in Exhibit __(RJM-WH-2). The pro forma average number of consumers is based on the number of consumers as of December 2009. As indicated in the footnotes on page 4 of Exhibit __(RJM-WH-2), adjustments were made to reflect the expiring of Economic Development Credits and the net effect of losing and gaining a consumer during 2009. Otherwise, the pro forma energy by rate class is the actual test year average usage by consumer multiplied by the number of pro forma consumers. Pro forma year demand was calculated by scaling the actual test year demand by the ratio of actual test year to pro forma year energy; i.e., I have adopted the 2009 class average load factor.

Q. Please explain the rate class labeled as Local Access Charge ("LAC")?

A. Mid-Kansas through Wheatland provides delivery service to wholesale users of its 34.5 kV facilities under the former Aquila LAC rate of $1.48 per kW. This rate class refers to the billing determinants and revenue from the LAC that should be included in the Test Year for this service.

Q. You have treated the LAC differently than what was experienced in 2009. Please explain why this change was necessary.

A. During 2009, Wheatland submitted its expenses for ownership and maintenance of these facilities to Mid-Kansas for reimbursement. Mid-Kansas then collected this cost from Wheatland via its wholesale rate formula that was in effect during 2009, along with a portion from the third-party users of the 34.5 kV facilities. The revenue collected from third-party users was based on the former Aquila rate of $1.48 per kW. As of the Mid-Kansas wholesale rate that went into effect in early 2010, this reimbursement and wholesale rate recovery ceased. Mid-Kansas continues to bill and collect from the third-party users (i.e., wholesale customers) and remits the revenue collected to Wheatland based on the $1.48 per kW. I have, therefore, included the $105,512 of LAC revenue as rate schedule revenue which is based upon 2009 billing units.

Q. How was the retail Energy Cost Adjustment ("ECA") determined in the calculation of revenue under present rates?

A. The ECA used to determine revenue under present rates was determined based on the wholesale ECA collected from Wheatland during 2009 out of the revenues collected by Wheatland under Mid-Kansas' current rates and tariffs. The ECA is a pass through of the Mid-Kansas wholesale ECA.

Q. Did the Stipulation and Agreement ("S&A") approved by the Commission in Docket 969 include a wholesale ECA revenue requirement component?

A. Yes.

Q. Why have you used the historical wholesale ECA charges to Wheatland rather than the wholesale ECA charge as was contained in the S&A?

A. I believe the actual wholesale ECA charges from Mid-Kansas to Wheatland are more appropriate to use in this case. The wholesale ECA amounts contained in the S&A were based on that filing's test year and the stipulated rate design. Therefore, while it is the best estimate of the wholesale ECA under the new wholesale rate design, it is still an estimate; and the amount Wheatland will pay in ECA charges under the new wholesale rate will be based upon future, unknowable factors. Use of the historical ECA charges is more reliable versus speculating on what they will be in the future.

Q. Have you compared the 2009 ECA charges with the ECA charges so far under the 2010 Mid-Kansas wholesale rate?

A. Yes. The 2009 ECA and the YTD 2010 ECA are shown in the following Table 3.

Table 3 Comparison of Actual 2009 and 2010 YTD Wholesale ECA		
Month	**2009 Actual ECA**	**2010 YTD Wholesale ECA**
	($/kWh)	($/kWh)
January	0.03645	0.04214
February	0.02847	0.03517
March	0.02939	0.03518
April	0.02754	0.03305
May	0.02575	0.03140
June	0.02599	0.03722
July	0.03103	0.04322
August	0.03212	0.04395
September	0.03167	0.03602
October	0.03733	
November	0.03664	
December	0.03300	
Average	0.3128	0.03751

Q. If you were to use the 2010 ECA charges, how would the results of your revenue requirements analysis change?

A. There would be no net effect. The power costs would increase; however, because the retail ECA is a pass through, the revenue would change by the same amount. In that sense, it does not matter what ECA is used for purposes of determining the overall rate change needed for the Wheatland division.

Q. Please describe the pro forma adjustments to the purchased power expense.

A. The pro forma Test Year purchased power expense is based on the Mid-Kansas wholesale rate as approved by the Commission in its January 11, 2010 order in Docket 969. The exception as noted above is that the ECA is per actual amounts billed to Wheatland.

Q. Please explain the remaining pro forma adjustments to the actual operating expenses.

A. The following briefly describes these adjustments.

Payroll Expense was adjusted to reflect the annual effect of the December 2009 wage increase.

Payroll Related Expense was adjusted to reflect the changes in payroll expense and the known rate changes.

Depreciation Expense was adjusted to reflect the annualization of December 2009 depreciation expense less the acquisition premium amortization.

Interest on Long-Term Debt was adjusted to reflect the annualization of the LT interest expense as of December 31, 2009. An adjustment was also made to reflect the refinancing of Wheatland's line-of-credit ("LOC") in the amount of $2,580,098.50 into a long-term note at an annual interest rate of 3.15 percent, which originated on June 28, 2010.

Rate Case Expense is an adjustment to Administrative and General ("A&G") based on an estimated rate case expense amortized over three years.

Property Tax Expense was adjusted for property taxes payable for 2010.

Non-Operating Income was adjusted to: 1) remove the Mid-Kansas reimbursements of 2009 34.5 kV expenses, 2) add back in the amortization of the acquisition premium below the line, and 3) add in 2009 K-1 income allocated to Wheatland by Mid-Kansas.

Q. Why was it necessary to remove the Mid-Kansas reimbursements to Wheatland for 2009 34.5 kV expenses?

A. This was necessary to reflect the change in how the cost is recovered under the new Mid-Kansas wholesale rate and the divisional retail rates. During 2009, Wheatland submitted costs of owning, operating and maintaining its 34.5 kV facilities to Mid-Kansas for reimbursement. Wheatland recorded these reimbursements as non-operating income during 2009. This situation ceased when Mid-Kansas' new wholesale rate went into effect in early 2010. It is, therefore, appropriate to remove the reimbursements booked during 2009 since they will not be recurring and in fact are currently not occurring.

Q. Why did you make an adjustment to include amortization of the Acquisition Premium below-the-line as a non-operating expense?

A. During 2009, Wheatland had booked the amortization of the acquisition premium, related to the Aquila acquisition, above-the-line in the category for Depreciation and Amortization Expense. However, the S&A in Docket No. 06-MKEE-524-ACQ ("Docket 524") on page 12 states:

> "21. The Acquisition Premium ("AP") relating to this transaction shall be amortized over a thirty-year period beginning with the Effective Date, and shall be included below-the-line in subsequent Mid-Kansas, Distribution Cooperative(s) and Southern Pioneer rate proceedings. The AP shall be considered for purposes of calculating TIER and other financial ratios and shall be considered in the calculation of TIER for purposes of determining if a refund is due as provided for herein."

I have, therefore, made an adjustment to Depreciation and Amortization Expense which is an above-the-line expense to remove the AP amortization. To include it below-the-line, I have adjusted Wheatland's non-operating expense by the same amount.

Q. Does the effect of your adjustment treat the amortization of the AP consistent with your understanding of the S&A in Docket 524?

A. Yes, it does. It seems clear from the above excerpt that the AP: 1) shall be amortized over thirty years, 2) shall be included below-the-line in subsequent rate proceedings and 3) shall be considered for purposes of calculating TIER. My treatment of the amortization of the AP meets each of these directives of the S&A.

Q. What are Wheatland's operating results for the 2009 and the Test Year?

A. Exhibit __(RJM-WH-3) summarizes the operating results for Wheatland on both an unadjusted and an adjusted basis for the Test Year ending on December 31, 2009. A summary of the Operating Statement is provided in Table 4.

Table 4
Wheatland Division
Statement of Operations - Present Rates

Description	12 Months Ending 12/31/09	Pro Forma Test Year
	($)	($)
Operating Revenue	22,068,352	22,198,091
Operating Expenses[5]	24,262,725	23,284,752
Net Operating Income	(2,194,373)	(1,086,662)

It should be emphasized that the Net Operating Income is stated before LT interest expense on LT debt is deducted, since LT interest plus margin requirements are treated together as the margin requirement.

Q. Please identify the Net Operating Income required in the Test Year to achieve a 2.00 TIER.

A. To achieve a TIER of 2.00, Wheatland needs to generate Net Operating Income (before LT interest) of $3,180,990.

Q. Please summarize the increase Mid-Kansas is requesting for the Wheatland division.

5 Before interest expense is deducted.

A. With Pro Forma Test Year Operating Expenses of $23,284,752 and LT Interest and Margin Requirements of $3,180,990, the total Pro Forma Test Year Revenue Requirements are calculated to be $26,465,742. Revenue for the present rates on a Pro Forma Test Year basis is determined to be $21,943,468. To achieve the targeted TIER of 2.00, revenue must therefore be increased by $4,267,651 or 19.45 percent. The following Table 5 presents a summary of revenue requirements analysis for the Test Year.

Table 5
Wheatland Division
Revenue Requirements Summary
TIER = 2.00 Objective

			($)
1.	Operating Expenses (Excluding Interest)		23,284,752
2.	Margin Requirements		
	a. Interest Expense		1,762,127
	b. Target TIER		2.00
	c. Total Margin Requirements (Before Interest)		3,524,255
	d. Less: Capital Credits		-
	e. Less: Non-Operating Income		343,265
	f. Net Operating Income Required		3,180,990
3.	Total Revenue Requirements		26,465,742
4.	Revenue From Present Rates		
	a. Tariff Revenue		21,943,468
	b. Other Operating Revenue		254,623
	c. Total Revenue		22,198,091
5.	Required Increase (Decrease)		4,267,651
		or	19.45%

Q. How have you determined the margin requirements for each Mid-Kansas division?

A. The margin requirements were determined using a TIER coverage ratio. TIER measures the ability of Wheatland to meet LT debt obligations. This is a common means of determining the margin requirements for electric cooperatives around the country, including in Kansas.

The basic formula for TIER is as follows:

$$\text{TIER} = \frac{\text{Patronage Capital and Margins plus Long-Term Interest Expense}}{\text{Long-Term Interest Expense}}$$

Q. What is the TIER for purposes of determining the margin requirements in this application?

A. After considering a number of factors, I recommend that the targeted TIER be set at 2.00. It is important that the retail rates produce adequate margins to allow the Wheatland division through the Mid-Kansas rates to: 1) achieve and maintain an adequate capital structure, 2) provide stability in terms of handling contingencies and extending the time in between rate adjustments, 3) retire member equity (often referred to as capital credits) and 4) provide members an ownership stake in the Cooperative.

While I believe there is support for a higher TIER, the KCC Staff has historically advocated for a 2.00 TIER in the rate regulation of electric cooperatives. For purposes of this case, Mid-Kansas has determined that a 2.00 TIER is appropriate.

Q. How does the requested TIER compare to industry results?

A. According to the most recent information available from the National Rural Utilities Cooperative Finance Corporation ("CFC") for its electric cooperative borrowers, the TIER for cooperatives on a national and state level is shown in the following Table 6.

Table 6
Summary of TIER
(2005-2009 Median Values)
Source: CFC Key Ratio Trend Analysis

Year	National	Kansas	National (2 best of 3 yrs)	Kansas (2 best of 3 yrs)
2005	2.20	2.49	2.47	2.67
2006	2.29	2.29	2.49	2.86
2007	2.24	2.36	2.40	2.81
2008	2.27	1.93	2.46	2.46
2009	2.30	2.47	2.48	2.61
Ave.	*2.26*	*2.31*	*2.46*	*2.82*

As can be seen in the above table, the median TIER in Kansas has recently ranged from 1.93 to 2.49, with an average of 2.31. When considering the two best of the three most recent calendar years, the range in Kansas is 2.46 to 2.86, with an average of 2.82.

It is important to keep in mind that compared to these national and state medians, Wheatland is somewhat unique. For example, since the acquisition was financed with debt, there is currently very little, if any, equity. In order to migrate towards a more balanced capital structure required to maintain access to lower cost debt, build reserves against contingencies, provide members with an ownership stake, and fund a portion of plant renewals, replacements and growth, Wheatland needs to achieve an adequate equity ratio. Without adequate funding of operations and plant investments from rates, the capital structure of Wheatland will continue to be dominated by debt, which potentially limits access to needed financing and increases debt costs and business risk. It also would cause Wheatland's native system members (i.e., those existing prior to the acquisition) to subsidize the acquired system members.

Q. What is the equity ratio for Wheatland?

A. Using 2009 year-end financial statements, I have summarized Wheatland's equity in Table 7 in terms of 1) percent of total capitalization and 2) percent of assets.

Table 7
Wheatland Equity Position
As of 12/31/09

1. Equity Percent of Total Capitalization			
Mid-Kansas Member	**Equity**	**Total Capitalization**	**Equity Ratio**
	($)	($)	(%)
Wheatland East	-4,511,814	38,231,275	-11.8
National Median (CFC borrowers for 2009)			47.63
State Median (CFC borrowers for 2009)			45.23

2. Equity Percent of Assets			
Mid-Kansas Member	**Equity**	**Assets**	**Equity Ratio**
	($)	($)	(%)
Wheatland East	-4,511,814	44,512,367	-10.1
National Median (CFC borrowers for 2009)			41.26
State Median (CFC borrowers for 2009)			39.53

In order to build equity, it is reasonable to target a TIER no lower than 2.00, which is actually below the recent average for cooperatives in the U.S. and Kansas.

Q. What happens to the margins achieved through rates for Wheatland?

A. Wheatland is structured as a cooperative. As such, at the end of the year, any operating margins generated during the year are allocated to the member-consumers, who are also the owners of the Cooperative, in proportion to each member-consumer's patronage. These margins are retained by the Cooperative for a period of time. Eventually these retained margins, sometimes referred to as patronage capital, will be retired or paid back to the members as capital credits. In the meantime, the margins are invested back into the system and provide the largest component of the Cooperative's equity. This helps to: 1) lower the cost and amount of borrowing and 2) contributes to financial stability, thereby reducing risk. Wheatland has no "outside" investors and has no incentive to increase margins to the detriment of the consumer since every consumer participates in ownership of the Cooperative. Rather, the objective is to provide safe, reliable electricity at the most economical price to the membership.

Q. Has the TIER approach to setting margin requirements for rural electric cooperatives been endorsed by the KCC in prior cases?

A. Yes. KCC Staff regularly considers TIER in evaluating rate change needs of electric cooperatives.

PART V - COST OF SERVICE ANALYSIS

Q. Have you prepared a retail COS study for each Mid-Kansas Member-System division?

A. Yes. A class COS analysis has been prepared to provide information that will be used in evaluating and designing proposed retail rates for Wheatland. The basic objective of a COS is to identify the cost of providing service to each rate class as a function of load and service characteristics. The methodology employed is often referred to as the "fully allocated average embedded" COS approach, meaning that: 1) costs are allocated on an average system-wide basis, and 2) embedded or accounting costs as recorded on the Cooperative's books are used in the analysis. I believe that this is generally the most appropriate technique to use in allocating cost responsibility to the various classes and developing rate design data for rural electric cooperatives.

Q. Please describe the general class COS you prepared for the Wheatland division.

A. Exhibit __(RJM-WH-4) includes the COS analysis for the Wheatland division. The detailed calculations and assumptions that go into the analysis are as follows:

Page	Description
1-3	Cost of Service Summary
4-5	Classification of Plant in Service
6-11	Classification of Revenue Requirements
12-13	Adjusted Statement of Operations
14-17	Summary of Classification Factors
18	Summary of Allocation of Revenue Requirements to Rate Classes
19	Allocation of Plant in Service to Rate Classes
20-22	Allocation of Revenue Requirements to Rate Classes
23	Rate Class Weighting Factors
24	Summary of Class Demands
25-26	Calculation of Class Demand Characteristics
27	Calculation of Outdoor Lighting Demand Characteristics
28-29	Development of Allocation Factors.

Q. Please explain the general procedure for conducting a COS study.

A. The basic procedure used to determine the cost responsibility of each consumer classification is as follows:

<u>Step 1</u> - Classify the plant account records into basic cost causative categories.

<u>Step 2</u> - Classify the Test Year expenses and margin requirement into the same cost causative categories.

<u>Step 3</u> - Develop allocation factors for each rate class.

<u>Step 4</u> - Allocate costs to the various rate classes using the class allocation factors developed for each cost causative category.

Q. Please explain the process of classification into cost causative categories.

A. Plant investments, Test Year expenses and margin requirement are classified into the following cost causative categories:

1. <u>Direct</u> - Costs which are directly attributable to one specific customer classification. Expense associated with security and street lighting is an example of a Direct Expense.
2. <u>Consumer</u> - Costs that are directly related to the number of customers and which do not vary significantly with the demand imposed on the system or the amount of energy consumed. Metering and customer accounting expenses best illustrate this type of expense.
3. <u>Capacity</u> - Costs which result from providing and maintaining in readiness for operation facilities required to meet the peak demand, whether it be the system peak, circuit peak or individual customer service peak. The expense of owning,

operating and maintaining a three-phase backbone feeder would fall within this category as would the demand charge from the purchased power expense.

4. Energy - Costs which are related to the amount of energy used. The major items in this category are the Energy Charge and ECA in the purchased power rate.

Each of these general cost causative categories is further subdivided as follows:

Direct	Consumer	Capacity	Energy
As Assigned	Secondary & Service Meter Customer Accounting	Power Supply Distribution Substation Primary Line Line Transformer	Power Supply

Q. Please explain the methodology used in assigning plant accounts to cost causative categories.

A. The cost causative classification of the various electric plant accounts is presented on pages 4 and 5 of Exhibit __(RJM-WH-4). The methodology used in assigning the plant accounts to the cost causative categories is discussed as follows:

1. Intangible Plant (Acct. 301 to 303) - The Intangible Plant accounts were prorated to the cost categories in the same relationship as the distribution plant allocations.
2. Land, Structures, Station and Battery (Accts. 360 to 363) - The Land and Land Rights, Structures and Improvements, Station Equipment, and Battery accounts were classified as capacity related since the facilities represented by the investment are generally dictated by capacity considerations.
3. Primary Line and Devices (Accts. 364, 365, 366, 367) - The Primary Line and Device accounts were assigned to the capacity component.

4. Line Transformers (Acct. 368) - Classification of the Line Transformer account was assigned to the capacity component.
5. Services and Meters (Accts. 369 and 370) - Because the investment in Services and Meters is basically independent of usage level, it was assigned entirely to the customer component.
6. Consumer Premise (Acct. 371) - The investment in installations on Consumer's Premises was assigned to Primary Line.
7. Street Lighting (Acct. 373) - Investment in street or security lighting facilities was assigned directly to the Lighting Class.
8. General Plant Accounts (Accts. 389 to 399) - The General Plant accounts were assigned to the cost causative categories in the same relationship as the total distribution plant allocations. Because the assignment of the investment in general plant has minimal impact on the classification of Test Year expenses, which ultimately is used to determine class COS responsibility, a more detailed analysis of general plant investment was not warranted.

Q. Please explain how revenue requirements were classified.

A. The Adjusted Operating Statement shown in Exhibit __(RJM-WH-4), pages 12-13, forms the basis for the COS analysis. Actual expenses by account for the historical 12-month period were used to establish the pattern of the Test Year cost breakdown to the various accounts.

The various components of the revenue requirements were classified to the four basic cost causative categories as presented on pages 6 through 11 of Exhibit __(RJM-WH-4). The factors used in the expense classification are summarized on pages 14 through 17 of Exhibit __(RJM-WH-4). The methodology and rationale for that methodology is discussed below:

1. Purchased Power (Acct. 555) - The demand and energy charge portions of the cost of Purchased Power were assigned to the capacity and energy components, respectively.
2. Distribution Operation and Maintenance (Accts. 580 - 598) - Distribution expense accounts that are related to specific plant accounts (Accts. 582, 583, 584, 585, 586, 587, 591, 592, 593, 594, 595, 596 and 597) were classified in proportion to the corresponding plant accounts. These expenses result from operating and maintaining the distribution plant and thus may be considered plant related. The remaining distribution expense accounts (Accts. 580, 581, 588, 589, 590 and 598) were prorated on the basis of the sum of the previously assigned distribution expense accounts. These accounts basically represent overhead or general distribution expenses.
3. Consumer Accounting (Accts. 901 - 905) - Consumer Accounting expenses were assigned in total to the consumer component since this expense is basically independent of energy usage or capacity requirements. Instead, these accounts are related to the number of consumers.
4. Consumer Service and Information and Sales (Accts. 907 - 916) - Consumer Service and Information and Sales expenses are also considered consumer related expenses.
5. Administrative and General (Accts. 920 - 932) - A&G expenses are common costs for which there exists no obvious relationship to the functional categories. Thus,

we have assigned them in proportion to the total of all other expenses without power supply.

6. Depreciation and Amortization (Accts. 403 - 407) - Depreciation and Amortization expense was allocated in proportion to the total plant account assignments.
7. Property Taxes (Acct. 408) - Property Taxes were assigned in proportion to the total plant account assignments.
8. Other Taxes, Other Interest, and Other Deductions - Other Taxes, Other Interest, and Other Deductions were assigned in a manner similar to the A&G Accounts.
9. Net Operating Income (Margin Requirement) - Since margin is comprised of interest expense, which is a function of plant investment, it is reasonable to classify this cost in proportion to the total plant assignments. This approach most nearly parallels the method used to determine target margin requirements (i.e., TIER method).

Q. Please discuss the allocation of costs to rate classes.

A. The allocation of the revenue requirement to each consumer classification is presented on page 18 of Exhibit __(RJM-WH-4). The allocations are based on various allocation factors that reflect certain cost causative drivers as discussed below:

1. Direct Cost Allocation - Costs specifically associated with street or security lighting facilities (investment and O&M) directly assigned to the Lighting Class are an example of a possible direct cost allocation.
2. Consumer Costs Allocations - Generally speaking, consumer-related costs were allocated to the various classes on the basis of the total number of consumers in each class. However, several adjustments were made in the general allocation

procedure to reflect differences in the cost of providing basic service. Weighting factors were developed on page 23 of Exhibit __(RJM-WH-4) to recognize the higher cost of three-phase service versus standard single-phase service for each subcategory of consumer-related cost. A "weighting factor" of 0.02 was used to allocate the consumer expense related to providing basic service to an individual security or street light. Because these lights make use of facilities and services which have been primarily provided for under other rate schedules, it may be argued that it costs no more to prepare a bill for a consumer with a security light than for one without. However, it seems only fair that the lighting classes should be required to pay a token portion of the consumer-related expense; hence, the 0.02 weighting factor.

3. <u>Capacity Cost Allocations</u> - Three different allocation factors were developed for the capacity component. (See pages 24 to 27 of Exhibit __(RJM-WH-4) for the development of class demands):

   a. Line transformer capacity-related costs were allocated in accordance with the estimated, undiversified non-coincidental peak demand of each consumer in each class as this definition of demand most closely approximates transformer capacity requirements.

   b. Primary line and substation capacity allocated costs were allocated using the Average and Excess Demand Method based on the average monthly coincidental demand for each class (not necessarily coincidental with the system). Distribution system capacity-related costs are a function not only of the system peak, but also the individual circuit and even consumer peak demand. The Average and Excess Demand Method gives recognition to the average demand imposed on the system by each class as well as the average monthly peak demand of the class (non-coincidental) and prevents any class from getting a "free ride" from a capacity standpoint.

c. Purchased power demand charges were allocated in accordance with the average monthly coincidental class demands ("12CP").

4. Energy Cost Allocations - Energy-related costs were allocated on the basis of total energy sales in each rate class.

Allocation factors for each category are developed on pages 28 and 29 of Exhibit __(RJM-WH-4).

Q. Please summarize the results of the COS study you performed for the Wheatland division.

A. Results obtained from the COS analysis are summarized in Tables 8, 9 and 10 on the following pages. Table 8 provides a comparison of the calculated cost of providing service to each rate class with the revenue generated under the present rates by that class.

Table 8 Wheatland Division Cost of Service Summary				
Rate Class	Revenue Present Rates[6]	Revenue Requirement	Increase (Decrease) Amount	Percent[7]
	($)	($)	($)	(%)
Residential (04-RS)	10,464,800	12,626,046	2,161,245	20.9
GS Small (04-GSS)	939,173	1,281,201	342,028	36.9
GS Small W/Space Heat (04-Rider 1)	27,743	61,654	33,911	123.7
GS Large (04-GSL)	8,428,985	9,892,594	1,463,609	17.6
GS Large W/Space Heat (04-Rider 1)	285,866	383,483	97,617	34.6
Industrial (04-IS)	440,461	518,902	78,441	18.0
Municipal Power (04-M-I)	11,475	17,963	6,488	57.2
Water Pumping (04-WP)	91,057	120,106	29,049	32.3
Irrigation (04-IP-I)	45,604	47,821	2,217	4.9
Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)	559,168	560,177	1,009	0.2
Total[8]	21,294,333	25,509,948	4,215,615	19.8

Table 9 shows a breakdown of the COS by cost category for each class.

Table 9 Wheatland Division Cost Allocation Summary						
	Power Supply		Trans-	Distribution		Total
Rate Class	Capacity	Energy	mission	Consumer	Capacity	COS
	($)	($)	($)	($)	($)	($)
Residential (04-RS)	2,383,799	4,792,033	195,326	1,241,247	4,013,640	12,626,046
GS Small (04-GSS)	234,738	437,533	18,889	216,371	373,670	1,281,201
GS Small W/Space Heat (04-Rider 1)	14,305	22,736	1,112	3,055	20,446	61,654
GS Large (04-GSL)	1,845,161	4,400,400	158,127	466,096	3,022,810	9,892,594
GS Large W/Space Heat (04-Rider 1)	86,737	150,168	6,864	12,522	127,192	383,483
Industrial (04-IS)	96,240	250,115	8,454	2,928	161,165	518,902
Municipal Power (04-M-I)	3,006	4,250	228	5,488	4,991	17,963
Water Pumping (04-WP)	25,334	46,185	2,028	8,509	38,050	120,106
Irrigation (04-IP-I)	9,240	13,876	710	5,673	18,322	47,821
Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)	53,334	167,022	7,107	156,201	176,512	560,177
Total	4,751,895	10,284,318	398,847	2,118,089	7,956,799	25,509,948

6 Includes an allocated share of Other Operating Revenue.

7 Percentage is calculated using only rate schedule revenue (excludes Other Operating Revenue).

8 The class COS excludes rate classes or consumers which are served under non-standard rates. Also excluded is the Local Access Charge category as that was evaluated separately.

Table 10 provides total costs by class expressed in terms of $/customer/month (consumer component) and ¢/kWh (capacity and energy components).

Table 10
Wheatland Division
Unit Cost Summary

Rate Class	Power Supply Capacity	Power Supply Energy	Trans-mission	Distribution Consumer	Distribution Capacity	Total Cost
	(¢/kWh)	(¢/kWh)	(¢/kWh)	($/mo.)	(¢/kWh)	(¢/kWh)
Residential (04-RS)	2.19	4.40	0.18	9.35	3.68	11.59
GS Small (04-GSS)	2.36	4.40	0.19	9.54	3.76	12.88
GS Small W/Space Heat (04-Rider 1)	2.77	4.40	0.22	14.14	3.95	11.92
GS Large (04-GSL)	1.84	4.40	0.16	35.25	3.02	9.89
GS Large W/Space Heat (04-Rider 1)	2.54	4.40	0.20	34.78	3.72	11.23
Industrial (04-IS)	1.69	4.40	0.15	40.67	2.83	9.12
Municipal Power (04-M-I)	3.11	4.40	0.24	13.45	5.16	18.59
Water Pumping (04-WP)	2.41	4.40	0.19	26.26	3.62	11.44
Irrigation (04-IP-I)	2.93	4.40	0.23	26.26	5.81	15.16
Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)	1.40	4.40	0.19	0.19	4.65	14.75
Total - Average	2.03	4.40	0.17	8.80	3.40	10.91

Q. Please describe how you determined the 34.5 kV system revenue requirements which is the basis for the LAC rate.

A. The 34.5 kV system provides subtransmission/distribution service to both retail and wholesale customers. A separate COS study was therefore performed to determine the cost of providing local access service on the 34.5 kV facilities. The resulting 34.5 kV Test Year revenue requirements were then divided by the total wholesale and retail monthly coincidental billing demands for the Test Year to produce the proposed monthly LAC.

Q. How did you determine the COS and rate methodology?

A. I have used the same methodology as was applied in determining the LAC for the other five Mid-Kansas Member-Systems in Docket 969. This methodology is based on principles of cost causation. The COS is contained in Exhibit __(RJM-WH-5).

Q. Please summarize the resulting proposed LAC for the Wheatland division.

A. I have determined the proposed LAC at $2.21 per kW-month.

Q. Will each of the Wheatland division's customers pay this LAC?

A. Yes. The proposed Wheatland divisional retail rates are based on the full revenue requirements of Wheatland including the local access facilities. The amount of wholesale or third-party LAC revenue is used as an offset to this revenue requirement as determined by the proposed LAC and wholesale billing units. Thus, the retail and wholesale customers using Wheatland's divisional local access facilities will pay the same LAC.

PART VI - RATE DESIGN

Q. How should the results of a COS be applied?

A. It is vital to recognize some of the inherent limitations of a COS study. First, it must be emphasized that a COS analysis, while basically an engineering and economic evaluation, is an art, not an exact science. There are many different methodologies, techniques and assumptions that have been and will continue to be advocated by rate analysts. Because the various philosophies and assumptions can significantly affect the results of the analysis, the results should be treated as providing an indication of the general range of class cost responsibility, not as precise values.

Second, a COS analysis is of necessity directed at determining the cost imposed by a rate class on the system rather than at determining the cost imposed by individual consumers within each classification. The cost responsibility of a specific individual consumer may or may not be entirely consistent with the cost allocations made to their assigned consumer classification. Furthermore, the study does not address the problem of maintaining relatively smooth transitions between the various rate classes or subclasses of consumers which may be eligible to receive service under more than one rate schedule.

Third, accurate demand characteristics and load factor data for individual consumer classes are often unavailable. Capacity allocations must therefore be made on the basis of estimates or "typical" data. These assumptions or estimates can have an effect on the end results.

Fourth, a COS analysis does not address itself to many of the other legitimate objectives of rate design such as consumer acceptance or the avoidance of excessively abrupt changes from the historical rate policies of the cooperative. In addition, it does not recognize the desire to keep each rate schedule competitive, in as much as possible, with the corresponding rate schedule of neighboring utilities or the need to keep the rate structure simple so that it is easily administered and understood by consumers.

With the above limitations in mind, a COS study may be used as a general guide for assigning cost responsibility (i.e., revenue requirements) to each of the customer classifications in a manner which avoids unjustifiable price discrimination. The study also provides information useful in designing the individual rate schedules and provides support for justifying rate differentials to retail customers.

Q. What objectives have you considered in developing the proposed rates?

A. There are many legitimate objectives that influence the design of rates. Some of the more important ones are as follows:

1. The proposed rates must develop the requisite total revenue.
2. The proposed rates should reflect the cost of providing service. No class or subclass should subsidize or be subsidized by another.
3. The rate schedules should be simple and concise to facilitate consumer acceptance and administration.
4. Abrupt departures from historical rate practices and levels should be avoided.
5. The rate structure should be acceptable to the membership.

6. Where there is a possibility of a consumer being eligible to receive service under more than one rate schedule, the transition should be made as smoothly as possible.
7. The rates should promote the efficient use of energy and system capacity.
8. Whenever possible, the rate schedule should be competitive with those of neighboring utilities and alternative energy sources.

It is generally not possible to fully accomplish all of the above objectives in developing rate schedules. Compromises based on judgment reflecting the policy of the utility must be made.

Q. You previously indicated that you propose to phase-in the required increase. Please explain.

A. The overall increase being proposed for the Wheatland division is $4,264,081 or 19.4 percent. Mid-Kansas acknowledges the significance of this increase and the impact it will have on its consumers, especially in this current economic climate. In order to balance the need for immediate financial relief and longer term financial sustainability with the concern for the rate and bill impact, Mid-Kansas is proposing to phase-in the increase over a two-year period. The first increase would go into effect with the Commission order, and the second is proposed to be effective 12 months later.

Q. How are you proposing to determine the required increase for the two-year phase-in?

A. The Phase 1 increase is designed around Wheatland achieving its minimum debt service coverage ("MDSC") ratio as determined by CFC. CFC requires Wheatland to achieve a minimum MDSC ratio of 1.35 based on adjusted test year debt service payments of $2,244,443. The Phase 2 increase then represents the difference between this "bare bone" minimum margin requirement and the margin requirements determined on a 2.00 TIER. The distribution of the proposed increase between Phase 1 and Phase 2 is shown below:

Phase 1 increase target:	$2,384,968 or 10.9 percent
Phase 2 increase target:	$1,879,113 or 7.7 percent[9]
Total increase target:	$4,264,081 or 19.4 percent

Q. Please describe how you allocated the rate increase between rate classes.

A. The first step in designing the proposed rates was to establish the Phase 2 proposed or targeted increase for each class. While the COS analysis played an important role in establishing the targeted increase for each class, other rate design objectives were considered, such as the need to avoid abrupt changes. In general, it is my belief that the principle of rate moderation (i.e., the need to avoid abrupt changes) should be used to temper the results of the COS analysis. Thus, the dollar and percentage change for each class as shown in Table 8, Cost of Service Summary, was tempered by experienced judgment in order to accomplish the overall rate design objectives.

Once the Phase 2 rates were determined, I established the Phase 1 rates in a manner that would step each rate and the rate design towards the ultimate Phase 2 rates while achieving the Phase 1 increase allocation.

9 The Phase 2 percentage increase is expressed as the incremental increase over Phase 1 rates.

Q. Have you established general guidelines for moderating the distribution of the requisite rate increase to the various classes?

A. Yes. Recognizing the principle of "rate moderation," I have adopted the following general guidelines in distributing the requisite rate increase to the various classes:

1. No class should receive an increase greater than one-and-one-half times the average.
2. No class should receive a rate decrease.

Q. Summarize the revenue impact of your proposed Phase 1 rates.

A. The rate design recommendations contained and discussed herein result in a $2,384,968 revenue increase, or 10.9 percent. This breaks down to a $2,332,925, or 10.7 percent, increase in retail rates and $52,043, or 49.3 percent, in the LAC rate charged to wholesale customers.

Q. Have you prepared a comparison of the Present and Proposed Rates for Phase 1?

A. Yes, I have. Exhibit __(RJM-WH-9) provides a comparison of the present versus proposed Phase 1 rates. The following Table 11 summarizes this comparison.

Table 11
Wheatland Division
Phase 1
Comparison of Revenue
Present and Proposed Rates

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	**Rate Class**	**Revenue Present Rates**	**Revenue Proposed Rates**	**Increase (Decrease) Amount**	**Increase (Decrease) Percent**
		($)	($)	($)	(%)
1	Residential Service (04-RS)	10,339,670	11,534,315	1,194,646	11.6
2	General Service Small (04-GSS)	927,943	1,076,765	148,822	16.0
3	General Service Large (04-GSL)	8,328,197	9,141,629	813,432	9.8
4	General Service Space Heating (04-Rider No. 1)	309,859	359,309	49,450	16.0
5	Industrial Service (04-IS)	435,195	478,508	43,314	10.0
6	Interruptible Industrial Service (04-INT)	660,257	724,811	64,554	9.8
7	Economic Development (04-EDR)	-	-	-	0.0
8	Real -Time Pricing (4-RTP)	129,461	130,107	646	0.5
9	Municipal Power Service (04-M-I)	11,337	13,148	1,810	16.0
10	Water Pumping Service (04-WP)	89,968	104,307	14,339	15.9
11	Irrigation Service (04-IP-I))	45,059	46,236	1,177	2.6
12	Temporary Service (04-CS)	8,528	9,438	910	10.7
13	Lighting	552,482	552,308	(174)	0.0
14	**Total Retail Rates**	21,837,956	24,170,881	2,332,925	10.7
15					
16	Local Access Charge Revenue - Third Party	105,512	157,555	52,043	49.3
17					
18	**Total All Rates**	21,943,468	24,328,436	2,384,968	10.9

Q. Summarize the revenue impact of your proposed Phase 2 rates.

A. The retail rate design recommendations contained and discussed herein result in an incremental $1,879,113, or 7.7 percent increase. By incremental I mean the increase over the Phase 1 rates. This increase would allow Wheatland to achieve a TIER of 2.00 under test year conditions.

Q. Have you prepared a comparison of the Present and Proposed Rates for Phase 2?

A. Yes, I have. Exhibit __(RJM-WH-11) provides a comparison of the present versus proposed Phase 2 rates. The following Table 12 summarizes this comparison.

Table 12
Wheatland Division
Phase 2
Comparison of Revenue
Present and Proposed Rates

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	**Rate Class**	**Revenue Present Rates**	**Revenue Proposed Rates**	**Increase (Decrease) Amount**	**Percent**
		($)	($)	($)	(%)
1	Residential Service (04-RS)	11,534,315	12,498,592	964,277	8.4
2	General Service Small (04-GSS)	1,076,765	1,199,406	122,641	11.4
3	General Service Large (04-GSL)	9,141,629	9,792,598	650,969	7.1
4	General Service Space Heating (04-Rider No. 1)	359,309	400,366	41,057	11.4
5	Industrial Service (04-IS)	478,508	513,173	34,664	7.2
6	Interruptible Industrial Service (04-INT)	724,811	773,879	49,068	6.8
7	Economic Development (04-EDR)	-	-	-	0.0
8	Real -Time Pricing (4-RTP)	130,107	130,775	668	0.5
9	Municipal Power Service (04-M-I)	13,148	14,659	1,511	11.5
10	Water Pumping Service (04-WP)	104,307	116,331	12,024	11.5
11	Irrigation Service (04-IP-I))	46,236	47,246	1,010	2.2
12	Temporary Service (04-CS)	9,438	10,156	718	7.6
13	Lighting	552,308	552,814	506	0.1
14	**Total Retail Rates**	24,170,881	26,049,994	1,879,113	7.8
15					
16	Local Access Charge Revenue - Third Party	157,555	157,555	-	
17					
18	**Total All Rates**	24,328,436	26,207,549	1,879,113	7.7

Q. What type of ECA is being proposed for the Wheatland division?

A. Wheatland is proposing a monthly ECA that captures the difference between the actual monthly average purchased power expense per kWh sold and the base purchased power expense per kWh sold as contained in this application. This is sometimes referred to as an ECA-2 and is the same type of ECA that was approved by the Commission for use in the other five Mid-Kansas division retail rates.

Q. Have you determined the base to be used in calculating the future ECA?

A. Yes. In Exhibit__(RJM-WH-12), I have calculated the ECA base at $0.064303 per kWh sold.

Q. Is Mid-Kansas proposing changes to other charges in addition to the rate schedules identified above?

A. No.

Q. Have you prepared rate schedules reflecting the proposed changes discussed in your testimony?

A. Yes. Exhibit __(RJM-WH-13) includes the present rate schedules. This exhibit is followed by Exhibit __(RJM-WH-14) that includes redline versions of present rate schedules showing all the proposed changes, additions and deletions. Finally, Exhibit __(RJM-WH-15) presents a "clean" version of proposed rate schedules.

Q. Why haven't you included a proposed Schedule PGS?

A. Under a separate docket, Mid-Kansas has applied for changes to this schedule on behalf of all the Mid-Kansas Member-Systems. I am deferring to that separate filing to determine any changes being proposed for this and related rate schedules.

Q. Does this conclude your prefiled Direct Testimony for the Mid-Kansas rates?

A. Yes, it does.

STATE OF MINNESOTA)
) ss.
COUNTY OF ISANTI)

VERIFICATION

Richard J. Macke, being duly sworn upon his oath, deposes and says that he is Richard J. Macke referred to in the foregoing document entitled "Prefiled Direct Testimony and Exhibits of Richard J. Macke" before the State Corporation Commission of the State of Kansas and that the statements therein were prepared by him or under his directions and are true and correct to the best of his knowledge, information, and belief.

Richard J. Macke

Richard J. Macke

Subscribed and sworn to me this 24th day of November, 2010.

Marilyn M. Cuellar

Notary Public

My Appointment Expires:

1/31/15

MARILYN M. CUELLAR
NOTARY PUBLIC - MINNESOTA
My Commission Expires Jan. 31, 2015

Exhibit 1 - Curriculum Vitae - Richard J. Macke

PSE

RICHARD J. MACKE
VICE PRESIDENT, RATES AND FINANCIAL PLANNING

SUMMARY OF EXPERIENCE AND EXPERTISE

- Over 14 years of experience in electric utility consulting.
- Specialized expertise in financial analyses with particular emphasis on utility finance, rate and cost of service matters, financial planning, and financial modeling.

PROFESSIONAL EXPERIENCE

Power System Engineering, Inc. – Minneapolis, MN (1999-present)

Vice President, Rates and Financial Planning (July 2010-present)
Leader, Rates and Financial Planning (April 2008-June 2010)
Senior Rate and Financial Analyst (2002-March 2008)
Rate and Financial Analyst (1999-2002)

As Vice President of Rates and Financial Planning Department at PSE, responsibilities include providing senior level consulting services to clients in the areas of cost of service, rate design, financial planning and forecasting, merger and acquisition analysis, and support. Additional responsibilities include strategic planning, litigation support, regulatory compliance, capital expenditure, and operational assessments and advisement.

Energy & Resource Consulting Group, LLC – Denver, CO (1998-1999)

Senior Analyst

Senior Analyst for financial, engineering and management consulting firm. Performed consulting services related to electric, gas, and water rate studies. Part of the Financial and Engineering Advisor Team contracted to the City Council of the City of New Orleans, LA to assist in various electric and gas utility matters. Provided expert testimony and participated in various regulatory proceedings involving the City Council, the Public Utilities Commission of Texas, and the Public Utilities Commission of Nevada. Provided general financial, management, and public policy support to clients.

Power System Engineering, Inc. - Blaine, MN (1996-1998)

Financial Analyst

Financial Analyst in Utility Planning and Rates Division. Emphasis on retail rate studies, including revenue requirements, and bundled/unbundled cost of service studies. Provided analysis used to support testimony, mergers and acquisitions cases, and financial forecasting.

Cenerprise, Inc. – Minneapolis, MN (February-May 1996)

Energy Sales Analyst Intern for NSP Subsidiary

Performed cost savings analyses for businesses, schools, and hospitals. Created training packages for use in other Cenerprise offices consisting of rate tariffs, preliminary consumption analysis, savings analysis, cost projections, and financial analysis.

RICHARD J. MACKE

EDUCATION

University of Minnesota, Minneapolis, MN
Masters of Business Administration (emphasis on Finance and Strategic Management), 2007

Bethel University, St. Paul, MN
Bachelor of Arts Degree in Business (emphasis on Finance and Marketing), Minor: Economics, 1996

ADDENDUM REFERENCES

Expert Testimony

PSE

RICHARD J. MACKE ADDENDUM - EXPERT TESTIMONY

Case or Jurisdiction	Docket No.	Description
Kansas	09-MKEE-969 -RTS	Mid-Kansas Electric Company, LLC, application for approval to make certain changes in the charges for electric services. Filed on behalf of Mid-Kansas and its member-owners: Lane-Scott Electric Cooperative, Inc.; Prairie Land Electric Cooperative, Inc.; Southern Pioneer Electric Company, Inc.; Victory Electric Cooperative Association, Inc.; Western Cooperative Electric Association, Inc.; and Wheatland Electric Cooperative, Inc.
Kansas	09-PNRE-563 -RTS	Pioneer Electric Cooperative, Inc., application to increase rates. Testimony filed on behalf of Pioneer.
Kansas	09-WHLE-681 -RTS	Wheatland Electric Cooperative, Inc., application to increase rates. Testimony filed on behalf of Wheatland.
Minnesota	E-111/ GR-03-261	Dakota Electric Association, application to increase rates. Testimony filed on behalf of Dakota.
Texas	2150	North Star Steel, appropriateness of settlement rates being charged by Entergy Gulf States, Inc. Testimony filed on behalf of North Star Steel before the Public Utilities Commission of Texas.

PSE

Exhibit 2 - Statement of Operations - Present Rates

Statement of Operations
Present Rates
For the Test Year Ended 12/31/09

(a) Line No.	(b) Description	(c) Actual Test Year [1]	(d) Adjustments [2]	(e) Pro Forma Test Year
1	**Operating Revenue**			
2	Sales of Electricity	21,813,729	$ 129,739	$ 21,943,468
3	Other	254,623		254,623
4	**Total Operating Revenue**	$ 22,068,352	$ 129,739	$ 22,198,091
5				
6	**Operating Expenses**			
7	Cost of Purchased Power	16,690,867	(1,063,490)	15,627,377
8	Transmission - O & M	94,681	9,655	104,337
9	Distribution - Operation	1,252,356	110,480	1,362,836
10	Distribution - Maintenance	715,897	40,112	756,009
11	Consumer Accounts	589,067	31,520	620,587
12	Consumer Service & Information	20		20
13	Sales	22,655		22,655
14	Administrative & General	1,837,953	34,028	1,871,981
15	Depreciation & Amortization	1,868,481	(140,278)	1,728,203
16	Taxes - Property	855,925		855,925
17	Taxes - Other	146,954		146,954
18	Interest on Long Term Debt	1,691,914	70,213	1,762,127
19	Other Interest Expense	139,972		139,972
20	Other Deductions	47,896		47,896
21	**Total Operating Expenses**	$ 25,954,639	$ (907,759)	$ 25,046,880
22				
23	**Net Operating Margins**	$ (3,886,287)	$ 1,037,498	$ (2,848,789)
24				
25	**Non-Operating Margins**			
26	Capital Credits	-		-
27	Non-Operating Margins - Interest	1,407		1,407
28	Non-Operating Margins - Other	1,418,309	(1,076,451)	341,858
29	**Total Non-Operating Margins**	$ 1,419,716	$ (1,076,451)	$ 343,265
30				
31	**Total Patronage Capital & Margins**	$ (2,466,571)	$ (38,953)	$ (2,505,524)

[1] See WH-Workpaper A for the 2009 statement of operations.
[2] See Page 2 for a summary of adjustments and page reference to supporting schedules.

Supporting Adjustment Schedules
Summary of Adjustments

(a) Description	(b) Page	(c) Amounts
I. Revenues		
Schedule A - Adjustment to Revenue	4	$ 129,739
II. Purchased Power Expense		
Schedule B - Purchased Power	9	$ (1,063,490)
III. Transmission O&M Expense		
Schedule C - Payroll	10	$ 183
Schedule D - Payroll Related Expenses	13	$ 400
Schedule H - Property Tax Expense	15	$ 9,256
		$ 9,655
IV. Distribution - Operations Expense		
Schedule C - Payroll	10	$ 30,044
Schedule D - Payroll Related Expenses	13	$ 65,671
Schedule H - Property Tax Expense	15	$ 14,765
		$ 110,480
V. Distribution - Maintenance Expense		
Schedule C - Payroll	10	$ 7,956
Schedule D - Payroll Related Expenses	13	$ 17,391
Schedule H - Property Tax Expense	15	$ 14,765
		$ 40,112
VI. Consumer Accounts Expense		
Schedule C - Payroll	10	$ 9,894
Schedule D - Payroll Related Expenses	13	$ 21,626
		$ 31,520
VII. Administrative and General Expense		
Schedule C - Payroll	10	$ 6,496
Schedule D - Payroll Related Expenses	13	$ 14,199
Schedule G - Rate Case Expense	15	$ 13,333
Schedule H - Property Tax Expense	15	$ 2,645
		$ 34,028
VIII. Depreciation Expense		
Schedule E - Depreciation	14	$ (140,278)
IX. Interest on Long Term Debt Expense		
Schedule F - Long Term Interest Expense	14	$ 70,213
X. Non-Operating Income		
Schedule I - 34.5kV Reimbursement	15	$ (1,076,451)

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Present Rates

I. Consumer and Sales Data for Test Year Ended 12/31/09 (As Recorded)

(a) Line No.	(b) Description	(c) Avg. No. Cons. [1]	(d) Energy Sales [1]	(e) Billing Demand [1]	(f) Revenue [1]
			(kWh)	(kW)	($)
1	Residential Service (04-RS)	11,080	109,108,745	N.A.	10,314,531
2	General Service Small (04-GSS)	1,922	10,112,604	N.A.	937,787
3	General Service Large (04-GSL)	1,061	102,665,774	273,838.6	8,233,328
4	General Service Space Heating (04-Rider No. 1)	50	4,095,668	12,976.0	318,666
5	Industrial Service (04-IS)	6	4,769,849	12,289.6	377,854
6	Interruptible Industrial Service (04-INT)	2	7,727,200	30,962.0	656,149
7	Economic Development (04-EDR)	2	1,859,278	5,638.7	122,913
8	Real -Time Pricing (4-RTP)	2	2,020,983	3,282.0	129,461
9	Municipal Power Service (04-M-I)	34	96,641	N.A.	11,162
10	Water Pumping Service (04-WP)	27	1,050,253	N.A.	89,518
11	Irrigation Service (04-IP-I))	18	315,540	N.A.	45,009
12	Temporary Service (04-CS)	27	51,293	N.A.	8,587
13	Lighting	4,484	3,798,089	N.A.	568,824
14					
15	**Total** [2]	14,231	247,671,917	338,986.8	21,813,787

[1] Figures for test year ended Dec 31, 2009 as reported by Wheatland and contained in WH-Workpaper-B and WH-Workpaper-C.
[2] Total number of consumers excludes Security Lighting.

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Present Rates

II. Consumer and Sales Data for Pro Forma Test Year

(a) Line No.	(b) Description	(c) Avg. No. Cons. [1]	(d) Energy Sales [2]	(e) Billing Demand	(f) Revenue [3]
			(kWh)	(kW)	($)
1	Residential Service (04-RS)	11,066	108,970,882	N.A.	10,339,670
2	General Service Small (04-GSS)	1,891	9,949,497	N.A.	927,943
3	General Service Large (04-GSL) [4,5]	1,102	100,065,139	272,432.2	8,328,197
4	General Service Space Heating (04-Rider No. 1)	48	3,931,841	12,976.0	309,859
5	Industrial Service (04-IS) [4]	6	5,687,609	14,209.5	435,195
6	Interruptible Industrial Service (04-INT)	2	7,727,200	30,962.0	660,257
7	Economic Development (04-EDR) [4]	-	-	-	-
8	Real -Time Pricing (4-RTP)	2	2,020,983	3,282.0	129,461
9	Municipal Power Service (04-M-I)	34	96,641	N.A.	11,337
10	Water Pumping Service (04-WP)	27	1,050,253	N.A.	89,968
11	Irrigation Service (04-IP-I))	18	315,540	N.A.	45,059
12	Temporary Service (04-CS)	27	51,293	N.A.	8,528
13	Lighting	4,484	3,798,089	N.A.	552,482
14	Local Acces Charge			71,292	105,512
15	**Total** [6]	14,175	243,664,968	405,153.4	21,943,468
	Historical Revenue				21,813,729
	Adjustment				129,739

1	Figures for test year ended Dec 31, 2009 as reported by Wheatland and contained in WH-Workpaper-B and WH-Workpaper-C.			
2	Energy sales are based on historical average energy usage per consumer.			
3	See Schedule A, pages 5 - 8.			
4	Expired Economic Development (04-EDR) Credits			
	Date of EDR GSL Expiration; Customer A - Feb 09, Customer B - May 09, Customer C - Jun 09			
	Moved to General Service Large (04-GSL)	1	941,518	3,370.8
	Moved to Industrial Service (04-IS), expired Sept 09	1	917,760	1,919.9
5	Adjustment for known additional customer in General Service Large (04-GSL) contained in WH-Workpaper-B			
	Customer Added	1	1,463,385	3,906.0
6	Total number of consumers excludes Security Lighting.			

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

II. Estimate of Pro Forma Test Year Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
Residential Service (04-RS)				$
Customer Charge	11,066	cons	$8.39	1,114,125
Delivery Charge				
Summer - All kWh	45,397,188	kWh	$0.06011	2,728,825
Winter (Nov-Jun)	60,772,192	kWh	$0.04576	2,780,936
Electric Heat Winter				
801-5800 kWh	2,801,502	kWh	$0.01901	53,257
Energy Cost Adjustment [1]	108,970,882	kWh	$0.03361	3,662,528
				10,339,670
General Service Small (04-GSS)				
Customer Charge	1,891	cons	$9.78	221,928
Delivery Charge				
Summer (July to Oct.)	3,672,710	kWh	$0.04504	165,419
Winter (Nov-Jun)	6,276,788	kWh	$0.03285	206,192
Energy Cost Adjustment [1]	9,949,497	kWh	$0.03361	334,404
				927,943
General Service Large (04-GSL)				
Customer Charge	1,102	cons	$11.18	147,844
Demand Charge per kW>9				
Summer (July to Oct.)	106,240.1	kW	$6.99	742,618
Winter (Nov-Jun)	166,192.1	kW	$4.47	742,879
Delivery Charge				
Summer (July to Oct.)	37,965,659	kWh	$0.03978	1,510,274
Winter (Nov-Jun)	62,099,480	kWh	$0.02933	1,821,378
Energy Cost Adjustment [1]	100,065,139	kWh	$0.03361	3,363,204
				8,328,197
General Service Space Heating (04-Rider No. 1)				
Customer Charge GSS	18		$9.78	2,112
Customer Charge GSL	30		$11.18	4,025
Demand Charge per kW>9				
Summer (July to Oct.)	4,385.0	kW	$6.99	30,651
Winter (Nov-Jun)	8,591.0	kW	$4.47	38,402
Energy Charge				
Summer (July to Oct.) GSS	37,076	kWh	$0.04504	1,670
Summer (July to Oct.) GSL	1,340,002	kWh	$0.03978	53,305
Winter (Nov-Jun)	2,554,764	kWh	$0.01861	47,544
Energy Cost Adjustment [1]	3,931,841	kWh	$0.03361	132,150
				309,859
Industrial Service (04-IS)				
Customer Charge	6	cons	$100.62	7,245
Demand Charge				
Summer (July to Oct.)	4,964.5	kW	$10.62	52,723
Winter (Nov-Jun)	9,245.0	kW	$7.43	68,690
Delivery Charge				
Summer (July to Oct.)	2,041,695	kWh	$0.02717	55,473
Winter (Nov-Jun)	3,645,914	kWh	$0.01643	59,902
Energy Cost Adjustment [1]	5,687,609	kWh	$0.03361	191,161
				435,195

[1] See footnote 3 on page 9.

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

II. Estimate of Pro Forma Test Year Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
Interruptible Industrial Service (04-INT)				$
Customer Charge	2	cons	$100.62	2,415
Primay Service Discount				(5,669)
Demand Charge				
Non-Interruptible				
Summer (July to Oct.)	4,400	kW	$10.62	46,728
Winter (Nov-Jun)	8,800	kW	$7.43	65,384
Interruptible	30,962	kW	$4.47	138,400
Penalty		kW	$31.24	
Delivery Charge				
Summer (July to Oct.)	2,451,423	kWh	$0.02717	66,605
Winter (Nov-Jun)	5,275,777	kWh	$0.01643	86,681
Energy Cost Adjustment [1]	7,727,200	kWh	$0.03361	259,712
				660,257
Real -Time Pricing (4-RTP)				
Customer Charge	2	cons	$251.55	6,037
	2,020,983	kWh		123,424
				129,461
Municipal Power Service (04-M-I)				
Customer Charge	34	cons	$10.06	4,104
Delivery Charge				
Summer (July to Oct.)	57,003	kWh	$0.04880	2,782
Winter (Nov-Jun)	39,638	kWh	$0.03035	1,203
Energy Cost Adjustment [1]	96,641	kWh	$0.03361	3,248
				11,337
Water Pumping Service (04-WP)				
Customer Charge	27	cons	$16.21	5,252
Delivery Charge				
Summer (July to Oct.)	395,613	kWh	$0.06099	24,128
Winter (Nov-Jun)	654,640	kWh	$0.03863	25,289
Energy Cost Adjustment [1]	1,050,253	kWh	$0.03361	35,299
				89,968
Irrigation Service (04-IP-I))				
Demand Charge per hp	728	/HP/yr.	$29.92	21,782
Delivery Charge				
Summer (July to Oct.)	299,752	kWh	$0.04097	12,281
Winter (Nov-Jun)	15,788	kWh	$0.02476	391
Energy Cost Adjustment [1]	315,540	kWh	$0.03361	10,605
				45,059

1 See footnotc 3 on pagc 9.

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

II. Estimate of Pro Forma Test Year Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
Temporary Service (04-CS)				$
Delivery Charge	51,293	kWh	$0.13265	6,804
Energy Cost Adjustment [1]	51,293	kWh	$0.03361	1,724
				8,528
Private Area / Street Lighting (04-PAL-SL-I)				
Private Area Light (Coop owned)				
On Existing Pole				
100 W P.A.L. Cust 0%	778	lights	$6.42	59,937
100 W P.A.L. Cust 100%	2	lights	$1.43	
150 W P.A.L. Cust 0%	8	lights	$10.35	994
200 W P.A.L. Cust 0%	8	lights	$11.14	1,069
On New Pole (Wood)				
100 W P.A.L. Cust 0%	94	lights	$11.78	13,288
100 W P.A.L. Cust 100%	1	lights	$1.78	21
200 W P.A.L. Cust 0%	2	lights	$12.75	306
Flood Lights				
On Existing Pole				
150 W Flood Cust 0%	72	lights	$12.71	10,981
150 W Flood Cust 100%	2	lights	$2.03	49
400 W Flood Cust 0%	90	lights	$21.29	22,993
400 W Flood Cust 25%	2	lights	$16.75	402
400 W Flood Cust 75%	3	lights	$7.88	284
400 W Flood Cust 100%	2	lights	$3.56	85
1000 W Flood M.H. 0%	18	lights	$24.63	5,320
On New Pole (Wood)				
150 W Flood Cust 0%	12	lights	$14.66	2,111
400 W Flood Cust 0%	20	lights	$23.22	5,573
400 W Flood Cust 50%	1	lights	$13.23	159
1000 W Flood M.H. Cust 0%	5	lights	$39.32	2,359
Street Lights				
On Existing Pole				
100 W P.A.L. Cust 0%	6	lights	$7.30	526
150 W P.A.L. Cust 0%	5	lights	$8.09	485
On New Pole (Wood)				
100 W P.A.L. Cust 0%	4	lights	$11.78	565
200 W P.A.L. Cust 100%	3	lights	$2.22	80
On Existing Pole				
200 W Cobra Head Cust 0%	15	lights	$9.70	1,746
400 W Cobra Head Cust 0%	1	lights	$10.82	130
On New Pole (Wood)				
100 W Cobra Head Cust 0%	2	lights	$14.05	337
400 W Cobra Head Cust 0%	1	lights	$16.24	195
On New Pole (Steel)				
200 W Cobra Head Cust 0%	1	lights	$23.83	286
200 W Cobra Head Cust 50%	21	lights	$13.18	3,321
	1,179	lights		
Energy Cost Adjustment [1]	3,798,089	kWh	$0.03361	127,654

[1] See footnote 3 on page 9.

Schedule A
Summary of Consumers, Energy Sales, and
Revenue Under Present Rates
(Continued)

II. Estimate of Pro Forma Test Year Revenue Under Present Rates

Rate Class	Billing Determinants	Units	Rate	Revenue
Vapor Street Lighting Ornamental Service (04-OSL-V-I)				$
Coop Owned				
Acorn				
100 W HPS Cust 100%	5	lights	$2.90	174
250 W HPS Cust 100%	145	lights	$3.62	6,299
Single Globe				
70 W HPS Cust 100%	47	lights	$2.56	1,444
Lantern				
100 W HPS Cust 100%	13	lights	$3.03	473
250 W HPS Cust 100%		/mo.	$3.75	
Shoebox				
100 W HPS Cust 100%	5	lights	$3.35	201
250 W HPS Cust 100%	16	lights	$4.07	781
400 W HPS Cust 100%	44	lights	$4.93	2,603
	275	lights		
Street Lighting Service (04-SL-I) Frozen				
175 W MV 7000 Lumens	1,388	lights	$6.88	114,593
Controlled Private Area Lighting (04-PAL-I) Frozen				
100 W HPS/175 W MV	606	lights	$6.42	46,686
200 W HPS/400 W MV	56	lights	$11.14	7,486
150 W HPS/400 W MV (Flood)	73	lights	$12.71	11,134
400 W HPS/1000 W MV (Flood)	72	lights	$21.29	18,395
	807	lights		
Vapor Street Lighting Ornamental Service (04-OSL-V-I)				
100 W HPS/150 W MV	482	lights	$7.30	42,223
150 W HPS/250 W MV	122	lights	$8.09	11,844
200 W HPS/400 W MV	231	lights	$9.70	26,888
	835	lights		
Total Lighting	4,484	lights		552,482
Local Acces Charge				
Demand Charge	71,292	kW	$1.48	$ 105,512
Grand Total	243,664,968	kWh		21,943,468

Schedule B
Pro Forma Purchased Power Expense and Adjustment

Mid-Kansas Electric Company, LLC						
	Units		Pro Forma Test Year			
Description	Purchased[1]		Rate [2]		Amount	
Demand Charge	538,548	kW-mo.	$6.29	/kW	$	3,387,466
Energy Charge	262,190,821	kWh	$0.009896	/kWh	$	2,594,640
ECA Rate [3]	262,190,821	kWh	$0.030976	/kWh	$	8,121,691
OATT Rate					$	1,523,580
Energy 3-2-1 Member Credits					$	-
Total	262,190,821	kWh	0.0596	/kWh	$	15,627,377

Pro Forma Purchased Power Expense	$	15,627,377
Pro Forma Adjustment	$	(1,063,490)
Historical Test Year Purchased Power Expense	$	16,690,867

1 Pro-Forma kWh sales adjusted for line loss, Demand units calculated using historical year average load factor.

2 Current MKEC wholesale rates ECA is 2009 historical amounts.

3 Reference WH-Workpaper-D. Equivalent Retail ECA equal to $0.03361 per kWh.

Schedule C
Adjustment to Payroll Expense

I. Adjustments to Payroll Expense [1]

A. Actual wages recorded during the test year.			
1. From January 1, 2009 to November 30, 2009 payroll			$ 2,490,601
2. From December 1, 2009 to December 31, 2009 payroll			$ 256,045
			$ 2,746,645
B. Adjustments to annualize December 1, 2009 payroll increase.			
1. Test Year payroll prior to increase		$ 2,490,601	
2. Percent increase		3.50%	
3.	Increase		$ 87,171
	Subtotal		$ 2,833,816
C. Total Pro Forma Test Year Payroll Increase			
1. Pro Forma Test Year Payroll			$ 2,833,816
2. Less: Test Year Payroll			$ 2,746,645
3.	Total Payroll Increase		$ 87,171

II. Summary

	Total
1. Wages booked in Test Year	$ 2,746,645
2. Adjustments (Schedule C, Part I)	
Test Year Changes	
a. Increase in Wages	$ 87,171
Total Adjustments	$ 87,171
3. Total Pro Forma Test Year Payroll	$ 2,833,816

III. Allocation of Payroll Adjustment to Expense Categories

Category		Payroll Recorded in Test Year	Allocation Factor	Adjustment
Transmission		$ 5,761	0.21%	$ 183
Distribution Operations		$ 946,645	34.47%	$ 30,044
Distribution Maintenance		$ 250,688	9.13%	$ 7,956
Consumer Accounts		$ 311,742	11.35%	$ 9,894
Consumer Service		$ -	0.00%	$ -
Sales Expense		$ -	0.00%	$ -
Admin. and General		$ 204,677	7.45%	$ 6,496
Regulatory Expense		$ -	0.00%	$ -
	Sub-total	$ 1,719,513	62.60%	$ 54,390
Other		$ 1,027,133	37.40%	$ 32,598
	Total	$ 2,746,645	100.00%	$ 87,171

[1] Reference WH-Workpaper-E

Schedule D
Adjustment to Payroll Related Expenses

		Total
Total Change in Payroll per Schedule C [1]	$	87,171
A. Retirements & Pension		
1. Adjustment due to increase in payroll		
a. Rate		12.86%
b. Adjustment	$	11,212
2. Adjustment due to increase in rate		
a. Total pro forma payroll	$	2,833,816
b. Change in rate		4.50%
c. Adjustment	$	127,522
3. Subtotal Retirements & Pension	$	138,734
B. 401K		
1. Adjustment due to increase in payroll		
a. Rate		5.08%
b. Adjustment	$	4,432
2. Adjustment due to increase in rate		
a. Total pro forma payroll	$	2,833,816
b. Change in rate		0.00%
c. Adjustment	$	-
3. Subtotal 401K	$	4,432
C. Short Term Disability		
1. Adjustment due to increase in payroll		
a. Rate		0.23%
b. Adjustment	$	201
2. Adjustment due to increase in rate		
a. Total pro forma payroll	$	2,833,816
b. Change in rate		0.00%
c. Adjustment	$	-
3. Subtotal Short Term Disability	$	201

[1] Reference WH-Workpaper-E

Schedule D
Adjustment to Payroll Related Expenses

		Total
Total Change in Payroll per Schedule C [1]	$	87,171
D. Workmen's Compensation		
1. Adjustment due to increase in payroll		
a. Rate		1.05%
b. Adjustment	$	919
2. Adjustment due to increase in rate		
a. Total pro forma payroll	$	2,833,816
b. Change in rate		0.00%
c. Adjustment	$	-
3. Subtotal Workmen's Compensation	$	919
E. Hospitilization Insurance		
1. Adjustment due to increase in payroll		
a. Rate		19.60%
b. Adjustment	$	17,082
2. Adjustment due to increase in rate		
a. Total pro forma payroll	$	2,833,816
b. Change in rate		0.00%
c. Adjustment	$	-
3. Subtotal Hospitilization Insurance	$	17,082
F. State and Federal Unemployment		
1. Adjustment due to increase in payroll		
a. Rate		0.12%
b. Adjustment	$	103
2. Adjustment due to increase in rate		
a. Total pro forma payroll	$	2,833,816
b. Change in rate		0.20%
c. Adjustment	$	5,611
3. Subtotal State and Federal Unemployment	$	5,714
G. Group Term Life		
1. Adjustment due to increase in payroll		
a. Rate		0.74%
b. Adjustment	$	646
2. Adjustment due to increase in rate		
a. Total pro forma payroll	$	2,833,816
b. Change in rate		0.00%
c. Adjustment	$	-
3. Subtotal Group Term Life	$	646

[1] Reference WH-Workpaper-E

Schedule D
Adjustment to Payroll Related Expenses

		Total
Total Change in Payroll per Schedule C [1]	$	87,171
H. FICA		
1. Adjustment due to increase in payroll		
a. Rate		7.63%
b. Adjustment	$	6,651
2. Adjustment due to increase in rate		
a. Total pro forma payroll	$	2,833,816
b. Change in rate		0.00%
c. Adjustment	$	-
3. Subtotal FICA	$	6,651
I. Summary		
1. Retirements & Pension	$	138,734
2. 401K	$	4,432
3. Short Term Disablility	$	201
4. Workmen's Compensation	$	17,082
5. Hospitalization Insurance Expense	$	17,082
6. State and Federal Unemployment	$	5,714
7. Life Insurance	$	646
8. Sub-Total	$	183,891
9. FICA	$	6,651
10. Total	$	190,542

J. Allocation Payroll Related Expense Adjustments to Expense Categories

Category	Payroll Recorded in Test Year	Allocation Factor	Adjustment
Generation	-	0.00%	$ -
Transmission	5,761	0.21%	$ 400
Distribution Operations	946,645	34.47%	$ 65,671
Distribution Maintenance	250,688	9.13%	$ 17,391
Consumer Accounts	311,742	11.35%	$ 21,626
Consumer Service	-	0.00%	$ -
Sales Expense	-	0.00%	$ -
Admin. and General	204,677	7.45%	$ 14,199
Regulatory Expense	-	0.00%	$ -
Sub-total	$ 1,719,513	62.60%	$ 119,287
Other	1,027,133	37.40%	$ 71,255
Total	$ 2,746,645	100.00%	$ 190,542

[1] Reference WH-Workpaper-E

Schedule E
Adjustment to Depreciation Expense

A. Depreciation on Existing Plant [1]		
1. Depreciation Expense Recorded for Plant as of December 31, 2009	$	156,202
2. Less: Acquisisition Premium Amortization for December 31, 2009	$	12,185
2. Multiply by 12 Months		12
3. Normalized Depreciation Expense on Existing Plant	$	1,728,203
B Summary		
1. Total Depreciation Expense for the Pro Forma Test Year	$	1,728,203
2. Less: Actual Depreciation Expense recorded during the Test Year	$	1,868,481
3. Adjustment to Depreciation Expense	$	(140,278)

Schedule F
Adjustment to Long Term Interest Expense

A. Interest on Existing Loans [1]		
1. Interest Expense for the month of December 31, 2009	$	140,071
2. Multiply by 12 Months		12
3. Normalized Interest Expense on Existing Loans	$	1,680,854
B. Interest on New Loans		
1. New Loans Requisitioned June 28, 2009	$	2,580,099
2. Interest Rate.		3.15%
3. Estimated Interest Expense on New Loan Funds	$	81,273
C. Summary		
1. Interest Expense for the Pro Forma Test Year		
a. Interest on Existing Debt	$	1,680,854
b. Interest on New Debt	$	81,273
c. Total	$	1,762,127
2. Less: Actual Interest Expense recorded during the Test Year	$	1,691,914
3. Adjustment to Interest on Long Term Debt	$	70,213

[1] Reference WH-Workpaper-E

Schedule G
Adjustment for Rate Case Expense

1. Estimated Rate Case Expense	$	40,000
2. Amortize Over 3 Years		3
3. Adjustment to A&G for Estimated Rate Case Expense	$	13,333

Schedule H
Adjustment to Property Tax Expense

A. Property Taxes [1]

Category		Historical Year		2010		Adjustment
Property taxes paid by category						
Transmission	$	179,744	$	189,000	$	9,256
Distribution Operations	$	286,735	$	301,500	$	14,765
Distribution Maintenance	$	286,735	$	301,500	$	14,765
Consumer Accounts	$	51,356	$	54,000	$	2,645
Administrative & General	$	51,356	$	54,000	$	2,645
	$	855,925	$	900,000		

Schedule I
Adjustment to Non-Operating Income

A. Non-Operating Income

1. Non-Operating Income for the Period Ending December 31, 2009	$	1,418,309
2. Less: 34.5kV Reimbursement through December 31, 2009	$	1,445,743
3. Less: Amortization of Acquisition Premium.	$	146,221
4. Plus: Adjustment of K-1 income for 2009	$	515,514
5. Normalized Non-Operating Income for the Pro Forma Test Year	$	341,858
6. Adjustment to Non-Operating Income	$	(1,076,451)

Exhibit 3 - Revenue Requirements

Determination of Revenue Requirements -- Summary
Times Interest Earned Ratio (TIER) Method

(a)	(b)	(c)	(d)	(e)	(f)
		12/31/09	Pro Forma Test Year		
Line		Test Year	Present	Proposed Rates	
No.	Description	Actual	Rates	Phase 1	Phase 2
Financial Results From Rates		($)	($)	($)	($)
1	Total Revenue [1]	22,068,352	22,198,091	24,583,059	26,462,171
2	Operating Expense (before interest expense) [1]	24,262,725	23,284,752	23,284,752	23,284,752
3	Net Operating Income (before interest expense) [2]	(2,194,373)	(1,086,662)	1,298,306	3,177,419
4	Capital Credits [3]	-	-	-	
5	Non-Operating Margins - Interest [3]	1,407	1,407	1,407	1,407
6	Non-Operating Margins - Other [3]	1,418,309	341,858	341,858	341,858
7	Total Margin (before interest expense) [4]	(774,657)	(743,397)	1,641,572	3,520,684
8	Long Term Interest [3]	1,691,914	1,762,127	1,762,127	1,762,127
9	TIER [5]	(0.46)	(0.42)	0.93	2.00
Required Increase (Decrease) -TIER Objective					
10	Operating Expenses (excluding interest) [1]	24,262,725	23,284,752	23,284,752	23,284,752
11	Margin Requirements				
12	Interest Expense [3]	1,691,914	1,762,127	1,762,127	1,762,127
13	Target TIER [6]	2.00	2.00	2.00	2.00
14	Total Margin Required (before interest) [7]	3,383,828	3,524,255	3,524,255	3,524,255
15	Less: Capital Credits [3]	-	-	-	-
16	Less: Other Non-Operating Income [3]	1,419,716	343,265	343,265	343,265
17	Net Operating Income Required [8]	1,964,112	3,180,990	3,180,990	3,180,990
18	Total Revenue Requirements [9]	26,226,837	26,465,742	26,465,742	26,465,742
19	Revenue From Present Rates				
20	Tariff Revenue [1]	21,813,729	21,943,468	24,328,436	26,207,549
21	Other Operating Revenue [1]	254,623	254,623	254,623	254,623
22	Total Revenue [10]	22,068,352	22,198,091	24,583,059	26,462,171
23	Required Increase (Decrease) [11]	4,158,485	4,267,651	1,882,683	3,570
24	Percent Increase (Decrease) [12]	19.06	19.45	7.74	0.01

1 See Exhibit (RJM-WH-2).
2 Line 1 minus Line 2.
3 See Exhibit (RJM-WH-2), page 1.
4 Line 3 plus Line 4 plus Line 5 plus Line 6.
5 Line 7 divided by Line 8.
6 As determined by MKEC and Wheatland.
7 Line 12 times Line 13.
8 Line 14 minus line 15 minus Line 16.
9 Line 10 plus Line 17.
10 Line 20 plus Line 21.
11 Line 18 minus Line 22.
12 Line 23 divided by Line 20.

Exhibit 4 - Cost of Service Analysis

Cost of Service Summary
Revenue Requirements Summary – BUNDLED

Line No.	Description	Total	Residential (04-RS)	GS Small (04-GSS)	GS Small W/Space Heat (04-Rider 1)	GS Large (04-GSL)	GS Large W/Space Heat (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)
1	**Revenue Requirements**											
2	Revenue Requirements	25,509,948	12,626,046	1,281,201	61,654	9,892,594	383,483	518,902	17,963	120,106	47,821	560,177
3												
4	**Present Rates**											
5	Revenue-Present Rates	21,039,710	10,339,670	927,943	27,412	8,328,197	282,448	435,195	11,337	89,968	45,059	552,482
6	Revenue Credits	254,623	125,131	11,230	332	100,788	3,418	5,267	137	1,089	545	6,686
7		21,294,333	10,464,800	939,173	27,743	8,428,985	285,866	440,461	11,475	91,057	45,604	559,168
8												
9	Required Incr./(Decr) [1]	4,215,615	2,161,245	342,028	33,911	1,463,609	97,617	78,441	6,488	29,049	2,217	1,009
10	Percent	20.04%	20.90%	36.86%	123.71%	17.57%	34.56%	18.02%	57.23%	32.29%	4.92%	0.18%
11												

[1] The total increase requirement is reduced by the amount of LAC revenue offsets as shown in Exhbit 4, page 12.

Cost of Service Summary
Class Allocation Summary – BUNDLED

Line No.	Category	Total	Residential (04-RS)	GS Small (04-GSS)	GS Small W/Space Heat (04-Rider 1)	GS Large (04-GSL)	GS Large W/Space Heat (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)
19	**Power Supply**											
20	Direct											
21	Wholesale Cost											
22	Allocated Cost											
23	Subtotal											
24	Capacity Related											
25	Wholesale Cost	4,751,895	2,383,799	234,738	14,305	1,845,161	86,737	96,240	3,006	25,334	9,240	53,334
26	Allocated Cost											
27	Subtotal	4,751,895	2,383,799	234,738	14,305	1,845,161	86,737	96,240	3,006	25,334	9,240	53,334
28	Energy Related											
29	Wholesale Cost	10,284,318	4,792,033	437,533	22,736	4,400,400	150,168	250,115	4,250	46,185	13,876	167,022
30	Allocated Cost											
31	Subtotal	10,284,318	4,792,033	437,533	22,736	4,400,400	150,168	250,115	4,250	46,185	13,876	167,022
32	Sub. Power Supply	15,036,213	7,175,833	672,271	37,041	6,245,561	236,905	346,354	7,255	71,519	23,116	220,356
33	**Transmission**											
34	Direct											
35	Capacity	398,847	195,326	18,889	1,112	158,127	6,864	8,454	228	2,028	710	7,107
36	Energy											
37	Allocated Cost											
38	Sub. Transmission	398,847	195,326	18,889	1,112	158,127	6,864	8,454	228	2,028	710	7,107
39	**Distribution**											
40	Direct	146,142										146,142
41	Consumer	1,971,947	1,241,247	216,371	3,055	466,096	12,522	2,928	5,488	8,509	5,673	10,059
42	Capacity	7,956,799	4,013,640	373,670	20,446	3,022,810	127,192	161,165	4,991	38,050	18,322	176,512
43	Energy											
44	Sub. Distribution	10,074,888	5,254,887	590,041	23,501	3,488,906	139,713	164,094	10,479	46,559	23,995	332,714
45												
46	**Total**	25,509,948	12,626,046	1,281,201	61,654	9,892,594	383,483	518,902	17,963	120,106	47,821	560,177

Cost of Service Summary

Rate Design Factors – BUNDLED

Line No.	Category	Units	Total	Residential (04-RS)	GS Small (04-GSS)	GS Small W/Space Heat (04-Rider 1)	GS Large (04-GSL)	GS Large W/Space Heat (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)
47	**Costs Broken Down by Function**												
48	**Power Supply**												
49	Direct												
50	Wholesale Cost	$/Mo./cons											
51	Allocated Cost	$/Mo./cons											
52	Subtotal												
53	Capacity Related												
54	Wholesale Cost	¢/kWh	2.03	2.19	2.36	2.77	1.84	2.54	1.69	3.11	2.41	2.93	1.40
55	Allocated Cost	¢/kWh											
56	Subtotal	¢/kWh	2.03	2.19	2.36	2.77	1.84	2.54	1.69	3.11	2.41	2.93	1.40
57	Energy Related												
58	Wholesale Cost	¢/kWh	4.40	4.40	4.40	4.40	4.40	4.40	4.40	4.40	4.40	4.40	4.40
59	Allocated Cost	¢/kWh											
60	Subtotal	¢/kWh	4.40	4.40	4.40	4.40	4.40	4.40	4.40	4.40	4.40	4.40	4.40
61	Sub. Power Supply	¢/kWh	6.43	6.59	6.76	7.16	6.24	6.94	6.09	7.51	6.81	7.33	5.80
62	**Transmission**												
63	Direct	¢/kWh											
64	Capacity	¢/kWh	0.17	0.18	0.19	0.22	0.16	0.20	0.15	0.24	0.19	0.23	0.19
65	Energy	¢/kWh											
66	Allocated Cost	¢/kWh											
67	Sub. Transmission	¢/kWh	0.17	0.18	0.19	0.22	0.16	0.20	0.15	0.24	0.19	0.23	0.19
68	**Distribution**												
69	Direct	$/Mo./cons	0.65										2.72
70	Consumer	$/Mo./cons	8.80	9.35	9.54	14.14	35.25	34.78	40.67	13.45	26.26	26.26	0.19
71	Capacity	¢/kWh	3.40	3.68	3.76	3.95	3.02	3.72	2.83	5.16	3.62	5.81	4.65
72	Energy	¢/kWh											
73	Sub. Distribution	¢/kWh	4.31	4.82	5.93	4.55	3.49	4.09	2.89	10.84	4.43	7.60	8.76
74	Total	¢/kWh	10.91	11.59	12.88	11.92	9.89	11.23	9.12	18.59	11.44	15.16	14.75
75	**Costs Broken Down by Classification**												
76	Direct	$/Mo./cons	0.65										2.72
77	Consumer	$/Mo./cons	8.80	9.35	9.54	14.14	35.25	34.78	40.67	13.45	26.26	26.26	0.19
78	Capacity	¢/kWh	5.60	6.05	6.30	6.94	5.02	6.47	4.67	8.51	6.23	8.96	6.24
79	Energy	¢/kWh	4.40	4.40	4.40	4.40	4.40	4.40	4.40	4.40	4.40	4.40	4.40
80	Total		10.91	11.59	12.88	11.92	9.89	11.23	9.12	18.59	11.44	15.16	14.75

Classification of Plant in Service – BUNDLED

Line No.	Acct. No.	Description	Class. Factor	Total	Power Supply Energy	Power Supply Capacity	Transmission Energy	Transmission Capacity	Dist. Substation Capacity	Dist. Substation Cons.	Primary Line Capacity	Primary Line Cons.	Line Transf. Capacity	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
1		**Intangible Plant**																
2	301	Organization	PLNT															
3	302	Franchises and consents	PLNT															
4	303	Miscellaneous intangible plant	PLNT															
5	301-303	Subtotal																
6																		
7		**Production Plant**																
8	310-346	Production Plant	PROD1															
9																		
10		**Transmission Plant**																
11	350-359	Transmission Plant	TRAN1	12,558,474				12,558,474										
12																		
13		**Distribution Plant**																
14	360	Land	LAND	65,835					65,835									
15	361	Structures	SUB															
16	362	Station	SUB	5,612,013					5,612,013									
17	363	Battery	SUB															
18	364	Poles, towers	PRI	10,188,102							10,188,102							
19	365	OH Cond	PRI	11,761,822							11,761,822							
20	366	UG Conduit	PRI															
21	367	UG Cond	PRI	1,403,636							1,403,636							
22	368	Transf	TRF	6,180,284									6,180,284					
23	369	Services	SERV	2,638,271											2,638,271			
24	370	Meters	MTR	1,306,289												1,306,289		
25	371	Cons Premise	ICON	605,748							605,748							
26	372	Leased Prop	LICON															
27	373	St. Light	STL	735,348														
28	360-373	Subtotal		40,497,347					5,677,848		23,959,309		6,180,284		2,638,271	1,306,289		
29																		
30		**General Plant**																
31	389	Land & Land Rights	PLNT	116,500				27,576	12,467		52,610		13,571		5,793	2,868		
32	390	Structures and Improve.	PLNT	1,922,880				455,152	205,780		868,347		223,989		95,618	47,343		
33	391	Office Furniture & Equip.	PLNT	1,796,841				425,318	192,292		811,430		209,308		89,350	44,240		
34	392	Transportation & Equipment	PLNT	1,156,596				273,770	123,775		522,304		134,728		57,513	28,477		
35	393	Stores Equipment	PLNT	30,854				7,303	3,302		13,933		3,594		1,534	760		
36	394	Tool, Shop & Garage Equip.	PLNT	261,649				61,933	28,001		118,157		30,479		13,011	6,442		
37	395	Laboratory Equipment	PLNT	691,197				163,608	73,969		312,136		80,515		34,371	17,018		
38	396	Power Operated Equipment	PLNT	996,223				235,809	106,612		449,881		116,046		49,539	24,528		
39	397	Communication Equipment	PLNT	244,160				57,793	26,129		110,259		28,441		12,141	6,011		
40	398	Miscellaneous Equipment	PLNT	5,782				1,369	619		2,611		673		288	142		
41	399	Other tangible property	PLNT															
42	389-399	Subtotal		7,222,683				1,709,631	772,946		3,261,668		841,345		359,157	177,830		
43																		
44		**Total Plant**		60,278,505				14,268,105	6,450,794		27,220,977		7,021,628		2,997,428	1,484,118		

Classification of Plant in Service – BUNDLED

Line No.	Acct. No.	Description	Class. Factor	Total	Residential (04-RS) Direct	GS Small (04-GSS) Direct	GS Small W/Space Heat (04-Rider 1) Direct	GS Large (04-GSL) Direct	GS Large W/Space Heat (04-Rider 1) Direct	Industrial (04-IS) Direct	Municipal Power (04-M-I) Direct	Water Pumping (04-WP) Direct	Irrigation (04-IP-I) Direct	Lighting \L-SL-I, DOI (PAL-I, SL-I] Direct
1		**Intangible Plant**												
2	301	Organization	PLNT											
3	302	Franchises and consents	PLNT											
4	303	Miscellaneous intangible plant	PLNT											
5	301-303	Subtotal												
6														
7		**Production Plant**												
8	310-346	Production Plant	PROD1											
9														
10		**Transmission Plant**												
11	350-359	Transmission Plant	TRAN1	12,558,474										
12														
13		**Distribution Plant**												
14	360	Land	LAND	65,835										
15	361	Structures	SUB											
16	362	Station	SUB	5,612,013										
17	363	Battery	SUB											
18	364	Poles, towers	PRI	10,188,102										
19	365	OH Cond	PRI	11,761,822										
20	366	UG Conduit	PRI											
21	367	UG Cond	PRI	1,403,636										
22	368	Transf	TRF	6,180,284										
23	369	Services	SERV	2,638,271										
24	370	Meters	MTR	1,306,289										
25	371	Cons Premise	ICON	605,748										
26	372	Leased Prop	LICON											
27	373	St. Light	STL	735,348										735,348
28	360-373	Subtotal		40,497,347										735,348
29														
30		**General Plant**												
31	389	Land & Land Rights	PLNT	116,500										1,615
32	390	Structures and Improve.	PLNT	1,922,880										26,651
33	391	Office Furniture & Equip.	PLNT	1,796,841										24,904
34	392	Transportation & Equipment	PLNT	1,156,596										16,030
35	393	Stores Equipment	PLNT	30,854										428
36	394	Tool, Shop & Garage Equip.	PLNT	261,649										3,626
37	395	Laboratory Equipment	PLNT	691,197										9,580
38	396	Power Operated Equipment	PLNT	996,223										13,808
39	397	Communication Equipment	PLNT	244,160										3,384
40	398	Miscellaneous Equipment	PLNT	5,782										80
41	399	Other tangible property	PLNT											
42	389-399	Subtotal		7,222,683										100,106
43														
44		**Total Plant**		60,278,505										835,454

Classification of Revenue Requirements – BUNDLED

Line No.	Acct. No.	Description	Class. Factor	Total	Power Supply Energy	Power Supply Capacity	Transmission Energy	Transmission Capacity	Dist. Substation Capacity	Dist. Substation Cons.	Primary Line Capacity	Primary Line Cons.	Line Transf. Capacity	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
1		**Power Supply**																
2		**Production**																
3	500-557	Fuel	FUEL															
4	500-557	Non-Fuel O&M - Demand	PROD1															
5	500-557	Non-Fuel O&M - Energy	PROD1															
6		Subtotal - Production																
7		**Purchases**																
8	555	Direct Assign. Chgs (Cr.)																
9	555	Substation Charges	SUB															
10	555	Demand Charges	PURKW-1	4,751,895		4,751,895												
11	555	Summer	PURKW-2															
12	555	Winter	PURKW-3															
13	555	Other	PURKW-4															
14	555	Energy Charges	PURKWH-1	10,284,318	10,284,318													
15	555	On-Peak	PURKWH-2															
16	555	Off-Peak	PURKWH-3															
17	555	Revenue Related Charges	REV															
18		Subtotal - Purchases		15,036,213	10,284,318	4,751,895												
19	500-557	Total Power Supply		15,036,213	10,284,318	4,751,895												
20																		
21		**Transmission**																
22	560-573	Operation & Maintenance	TRAN1	92,413				92,413										
23	555	Transmission - G&T Charges	TRAN2															
24		Total Transmission		92,413				92,413										
25																		
26		**Distribution**		35,832														
27	580	Oper. Super & Eng.	EX1	351,055							307,868					43,187		
28	581	Load Dispatch	EX1															
29	582	Oper. Station	SUB															
30	583	Oper. OH Line	PRI	800,483							800,483							
31	584	Oper. UG Line	PRI	41,093							41,093							
32	585	Oper. St. Lighting	STL															
33	586	Oper. Meters	MTR	118,082												118,082		
34	587	Oper. Cons. Install	ICON	197							197							
35	588	Oper. Misc. Oper.	EX1	17,413							15,271					2,142		
36	589	Rents	EX1															
37	590	Main. Super. & Eng.	EX2															
38	591	Main. Structure	SUB	127					127									
39	592	Main. Station	SUB	165,817					165,817									
40	593	Main. OH Line	PRI	447,322							447,322							
41	594	Main. UG Line	PRI	(2,754)							(2,754)							
42	595	Main. Line Transf.	TRF	6,662									6,662					
43	596	Main. St. Lighting	STL	35,832														
44	597	Main. Meters	MTR	47,558												47,558		
45	598	Main. Misc. Dist.	EX2	20,931					4,958		13,282		199			1,421		
46	580-598	Subtotal		2,049,818					170,903		1,622,762		6,861			212,390		

Classification of Revenue Requirements – BUNDLED

Line No.	Acct. No.	Description	Class. Factor	Total	Residential (04-RS) Direct	GS Small (04-GSS) Direct	GS Small W/Space Heat (04-Rider 1) Direct	GS Large (04-GSL) Direct	GS Large W/Space Heat (04-Rider 1) Direct	Industrial (04-IS) Direct	Municipal Power (04-M-I) Direct	Water Pumping (04-WP) Direct	Irrigation (04-IP-I) Direct	Lighting \L-SL-I, DOI (PAL-I, SL-I) Direct
1		**Power Supply**												
2		**Production**												
3	500-557	Fuel	FUEL											
4	500-557	Non-Fuel O&M - Demand	PROD1											
5	500-557	Non-Fuel O&M - Energy	PROD1											
6		Subtotal - Production												
7		**Purchases**												
8	555	Direct Assign. Chgs (Cr.)												
9	555	Substation Charges	SUB											
10	555	Demand Charges	PURKW-1	4,751,895										
11	555	Summer	PURKW-2											
12	555	Winter	PURKW-3											
13	555	Other	PURKW-4											
14	555	Energy Charges	PURKWH-1	10,284,318										
15	555	On-Peak	PURKWH-2											
16	555	Off-Peak	PURKWH-3											
17	555	Revenue Related Charges	REV											
18		Subtotal - Purchases		15,036,213										
19	500-557	Total Power Supply		15,036,213										
20														
21		**Transmission**												
22	560-573	Operation & Maintenance	TRAN1	92,413										
23	555	Transmission - G&T Charges	TRAN2											
24		Total Transmission		92,413										
25														
26		**Distribution**		35,832										
27	580	Oper. Super & Eng.	EX1	351,055										
28	581	Load Dispatch	EX1											
29	582	Oper. Station	SUB											
30	583	Oper. OH Line	PRI	800,483										
31	584	Oper. UG Line	PRI	41,093										
32	585	Oper. St. Lighting	STL											
33	586	Oper. Meters	MTR	118,082										
34	587	Oper. Cons. Install	ICON	197										
35	588	Oper. Misc. Oper.	EX1	17,413										
36	589	Rents	EX1											
37	590	Main. Super. & Eng.	EX2											
38	591	Main. Structure	SUB	127										
39	592	Main. Station	SUB	165,817										
40	593	Main. OH Line	PRI	447,322										
41	594	Main. UG Line	PRI	(2,754)										
42	595	Main. Line Transf.	TRF	6,662										
43	596	Main. St. Lighting	STL	35,832										35,832
44	597	Main. Meters	MTR	47,558										
45	598	Main. Misc. Dist.	EX2	20,931										1,071
46	580-598	Subtotal		2,049,818										36,903

Classification of Revenue Requirements – BUNDLED
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Power Supply Energy	Power Supply Capacity	Transmission Energy	Transmission Capacity	Dist. Substation Capacity	Dist. Substation Cons.	Primary Line Capacity	Primary Line Cons.	Line Transf. Capacity	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
47		**Consumer Acct., Service & Sales**																
48		**Consumer Accounting**																
49	901	Supervision	CACC	26,050													26,050	
50	902	Meter Reading Expense	CACC	369,835													369,835	
51	903	Records & Collections	CACC	77,619													77,619	
52	904	Uncollectible Accounts	CACC	147,084													147,084	
53	905	Misc. Customer Account	CACC															
54		Subtotal		620,587													620,587	
55																		
56		**Consumer Service & Info.**																
57	907	Supervision	CS															
58	908	Customer Assistance	CS															
59	909	Info. & Instruction	CS	20													20	
60	910	Misc. Cust Serv. & Info	CS															
61		Subtotal		20													20	
62																		
63		**Sales**																
64	911	Supervision	SALES															
65	912	Demonstrating & Selling	SALES															
66	913	Advertising	SALES	22,655													22,655	
67	916	Misc. Sales	SALES															
68		Subtotal		22,655													22,655	
69																		
70		**Prorated Operating Expenses**																
71	920-	**Administrative & General**																
72	932	Power Supply	EX6-PS															
73		Transmission	EX6-TR															
74		Distribution	EX6-D	1,836,655					116,554		1,106,708		4,679			144,848	438,698	
75		Subtotal - A&G		1,836,655					116,554		1,106,708		4,679			144,848	438,698	
76																		
77	408	**Other Taxes**																
78		Power Supply	EX6-PS															
79		Transmission	EX6-TR															
80		Distribution	EX6-D	146,954					9,326		88,550		374			11,590	35,101	
81		Subtotal - Other Taxes		146,954					9,326		88,550		374			11,590	35,101	
82																		
83	421-	**Miscellaneous Expense**																
84	426,431	Power Supply	EX6-PS															
85		Transmission	EX6-TR															
86		Distribution	EX6-D	187,868					11,922		113,203		479			14,816	44,874	
87		Subtotal - Misc. Expense		187,868					11,922		113,203		479			14,816	44,874	

Classification of Revenue Requirements – BUNDLED
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Residential (04-RS) Direct	GS Small (04-GSS) Direct	GS Small W/Space Heat (04-Rider 1) Direct	GS Large (04-GSL) Direct	GS Large W/Space Heat (04-Rider 1) Direct	Industrial (04-IS) Direct	Municipal Power (04-M-I) Direct	Water Pumping (04-WP) Direct	Irrigation (04-IP-I) Direct	Lighting (L-SL-I, DOI (PAL-I, SL-I) Direct
47		**Consumer Acct., Service & Sales**												
48		**Consumer Accounting**												
49	901	Supervision	CACC	26,050										
50	902	Meter Reading Expense	CACC	369,835										
51	903	Records & Collections	CACC	77,619										
52	904	Uncollectible Accounts	CACC	147,084										
53	905	Misc. Customer Account	CACC											
54		Subtotal		620,587										
55														
56		**Consumer Service & Info.**												
57	907	Supervision	CS											
58	908	Customer Assistance	CS											
59	909	Info. & Instruction	CS	20										
60	910	Misc. Cust Serv. & Info	CS											
61		Subtotal		20										
62														
63		**Sales**												
64	911	Supervision	SALES											
65	912	Demonstrating & Selling	SALES											
66	913	Advertising	SALES	22,655										
67	916	Misc. Sales	SALES											
68		Subtotal		22,655										
69														
70		**Prorated Operating Expenses**												
71	920-	**Administrative & General**												
72	932	Power Supply	EX6-PS											
73		Transmission	EX6-TR											
74		Distribution	EX6-D	1,836,655										25,167
75		Subtotal - A&G		1,836,655										25,167
76														
77	408	**Other Taxes**												
78		Power Supply	EX6-PS											
79		Transmission	EX6-TR											
80		Distribution	EX6-D	146,954										2,014
81		Subtotal - Other Taxes		146,954										2,014
82														
83	421-	**Miscellaneous Expense**												
84	426,431	Power Supply	EX6-PS											
85		Transmission	EX6-TR											
86		Distribution	EX6-D	187,868										2,574
87		Subtotal - Misc. Expense		187,868										2,574

Classification of Revenue Requirements – BUNDLED
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Power Supply Energy	Power Supply Capacity	Transmission Energy	Transmission Capacity	Dist. Substation Capacity	Dist. Substation Cons.	Primary Line Capacity	Primary Line Cons.	Line Transf. Capacity	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
88		**Fixed Charges**																
89	403-	**Depreciation**																
90	407	Power Supply	PROPLNT															
91		Transmission	TRNPLNT	306,434				306,434										
92		Distribution	DSTPLNT	1,355,581					190,056		801,998		206,875		88,312	43,726		
93		Subtotal - Depreciation		1,662,015				306,434	190,056		801,998		206,875		88,312	43,726		
94																		
95	408	**Property Taxes**																
96		Power Supply	REV															
97		Transmission	REV															
98		Distribution	REV	832,965														832,965
99		Subtotal - Property Taxes		832,965														832,965
100																		
101	427	**Interest-LT**																
102		Power Supply	PROPLNT															
103		Transmission	TRNPLNT															
104		Distribution	DSTPLNT	1,682,525					235,895		995,427		256,769		109,611	54,272		
105		Subtotal - Interest-LT		1,682,525					235,895		995,427		256,769		109,611	54,272		
106																		
107		**Required Margin**																
108		Power Supply	PROPLNT															
109		Transmission	TRNPLNT															
110		Distribution	DSTPLNT	1,339,260					187,768		792,342		204,384		87,248	43,199		
111		Subtotal - Required Margin		1,339,260					187,768		792,342		204,384		87,248	43,199		
112																		
113		**Summary of Revenue Requirements**																
114		Power Supply		15,036,213	10,284,318	4,751,895												
115		Transmission		398,847				398,847										
116		Distribution		10,074,888					922,424		5,520,989		680,421		285,171	524,841	1,161,935	832,965
117		**Total Revenue Required**		25,509,948	10,284,318	4,751,895		398,847	922,424		5,520,989		680,421		285,171	524,841	1,161,935	832,965

Classification of Revenue Requirements – BUNDLED
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Residential (04-RS) Direct	GS Small (04-GSS) Direct	GS Small W/Space Heat (04-Rider 1) Direct	GS Large (04-GSL) Direct	GS Large W/Space Heat (04-Rider 1) Direct	Industrial (04-IS) Direct	Municipal Power (04-M-I) Direct	Water Pumping (04-WP) Direct	Irrigation (04-IP-I) Direct	Lighting \L-SL-I, DOI (PAL-I, SL-I) Direct
88		**Fixed Charges**												
89	403-	**Depreciation**												
90	407	Power Supply	PROPLNT											
91		Transmission	TRNPLNT	306,434										
92		Distribution	DSTPLNT	1,355,581										24,615
93		Subtotal - Depreciation		1,662,015										24,615
94														
95	408	**Property Taxes**												
96		Power Supply	REV		N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
97		Transmission	REV		N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
98		Distribution	REV	832,965	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
99		Subtotal - Property Taxes		832,965										
100														
101	427	**Interest-LT**												
102		Power Supply	PROPLNT											
103		Transmission	TRNPLNT											
104		Distribution	DSTPLNT	1,682,525										30,551
105		Subtotal - Interest-LT		1,682,525										30,551
106														
107		**Required Margin**												
108		Power Supply	PROPLNT											
109		Transmission	TRNPLNT											
110		Distribution	DSTPLNT	1,339,260										24,318
111		Subtotal - Required Margin		1,339,260										24,318
112														
113		**Summary of Revenue Requirements**												
114		Power Supply		15,036,213										
115		Transmission		398,847										
116		Distribution		10,074,888										146,142
117		**Total Revenue Required**		25,509,948										146,142

Schedule B
Adjusted Statement of Operations
and Revenue Requirements

(a) Line No.	(b) Description	(c) Total System [1]	(d) Adjustment [2]	(e) LAC Revenue Credits [3]	(e) Adjusted System
	Operating Revenue	($)	($)		($)
1	Sales of Electricity	21,943,468	(798,246)	(105,512)	21,039,710
2	Other	254,623			254,623
3	Total Operating Revenue	22,198,091	(798,246)		21,294,333
4	**Operating Expenses**				
5	Cost of Purchased Power				
6	Demand	4,911,046	(159,151)		4,751,895
7	Energy	10,716,331	(432,013)		10,284,318
8	Transmission - O & M	104,337	-	(11,924)	92,413
9	Distribution - Operation	1,362,836	(34,514)	-	1,328,322
10	Distribution - Maintenance	756,009	(34,514)	-	721,495
11	Consumer Accounts	620,587	-		620,587
12	Consumer Service & Information	20	-		20
13	Sales	22,655	-		22,655
14	Administrative & General	1,871,981	(34,514)	(813)	1,836,655
15	Depreciation & Amortization	1,728,203	(34,514)	(31,674)	1,662,015
16	Taxes - Property	855,925	-	(22,960)	832,965
17	Taxes - Other	146,954	-		146,954
18	Other Interest Expense	139,972	-		139,972
19	Other Deductions	47,896	-		47,896
20	**Total Operating**				
21	Term Interest)	23,284,752	(729,218)	(67,371)	22,488,163
22	Long Term Interest	1,762,127	(34,514)	(45,089)	1,682,525
23	Required Margin [4]	1,418,862	(34,514)	(45,089)	1,339,260
24	**Revenue Requirements**	26,465,742	(798,246)	(157,548)	25,509,948

[1] See Exhibit__(RJM-WH-2), page 1.

[2] See page _ for calculation of adjustments for rates not included in the class cost of service analysis.

[3] Credits related to revenue generated by the Local Access Rate developed in Exhibit WH(RJM-5).

[4] Required Net Operating Income less Long Term Interest. See calculation below:

3,180,990 - \$1,762,127 = \$1,418,862

[4] Adjustment to included LAC revenue for test period.

2009 LAC Billing Units		71,292
Present LAC rate	$	1.48
Total Test Year LAC Income	$	105,512

Schedule B
Adjustment to Eliminate Revenue and Expenses Associated with Non-Standard Rates

1. Revenue [1]

			Present ($)	Proposed ($)
a.	Interruptible Industrial Service (04-INT)	=	660,257	724,811
b.	Real -Time Pricing (4-RTP)	=	129,461	130,107
c.	Temporary Service (04-CS)	=	8,528	9,438
d.	Total -- Revenue		798,246	864,355

2. Expenses

a.	Purchased Power Expenses [2]								
	Energy Charges:								
	Interruptible Industrial Service (04-INT)								
	Energy [3]	8,314,699	kWh	x	$0.040872	/kWh	=	339,841	
	Real -Time Pricing (4-RTP)								
	Energy [3]	2,174,638	kWh	x	$0.040872	/kWh	=	88,882	
	Temporary Service (04-CS)								
	Energy [3]	55,193	kWh	x	$0.059603	/kWh	=	3,290	
					Subtotal -- Energy Expenses			432,013	
	Demand Charges:								
	Interruptible Industrial Service (04-INT)								
	Demand [3]	14,203.6	kW	x	$9.12	/kW	=	129,523	
	Real -Time Pricing (4-RTP)								
	Demand [3]	3,249.0	kW	x	$9.12	/kW	=	29,628	
					Subtotal -- Demand Expenses			159,151	
	Total -- Purchased Power Expenses							591,164	
b.	Distribution - Operation						=	34,514	4
c.	Distribution - Maintenance						=	34,514	4
d.	Administrative and General						=	34,514	4
e.	Depreciation						=	34,514	4
f.	Interest						=	34,514	4
g.	Margin Requirements						=	34,514	4
h.	Subtotal							207,082	
i.	Total -- Expenses							$ 798,246	

[1] From Exhibit (RJM-WH-2), Schedule A.
[2] From Exhibit (RJM-WH-2), Schedule B.
[3] Amounts from Exhibit (RJM-WH-2), pages 6-7 plus line loss.
[4] Split remainder of revenue approximately equal between Distribution Operation and Maintenance, Administration and General, Depreciation, Interest and Margin Requirements.

Summary of Classification Factors -- BUNDLED

Line No.	Name	Description	Source	Total	Power Supply Energy	Power Supply Cap.	Transmission Energy	Transmission Capacity	Dist. Substation Cap.	Dist. Substation Cons.	Primary Line Cap.	Primary Line Cons.	Line Transf. Cap.	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
		Classification Factor Data																
1	PROPLNT	Production Plant	Plant															
2	TRNPLNT	Transmission Plant	Plant	12,558,474				12,558,474										
3	DSTPLNT	Distribution Plant	Plant	40,497,347					5,677,848		23,959,309		6,180,284		2,638,271	1,306,289		
4	PLNT	Prod, Trans, Dist. Subtotal	Plant	53,055,822				12,558,474	5,677,848		23,959,309		6,180,284		2,638,271	1,306,289		
5	EX1	Assigned Dist. Oper. Exp.	Rev Req	959,855							841,773					118,082		
6	EX2	Assigned Dist. Main. Exp.	Rev Req	700,565					165,945		444,568		6,662			47,558		
7	EX3	Dist. Oper. & Main.	Rev Req	2,049,818					170,903		1,622,762		6,861			212,390		
8	EX4	Assigned O & M Exp.	Rev Req	17,821,706	10,284,318	4,751,895		92,413	170,903		1,622,762		6,861			212,390	643,262	
9	EX4-PS	Power Supply	Rev Req	15,036,213	10,284,318	4,751,895												
10	EX4-TR	Transmission	Rev Req	92,413				92,413										
11	EX4-D	Distribution	**2,693,080**	2,693,080					170,903		1,622,762		6,861			212,390	643,262	
12	EX5	Rev. Req. Less Margin	Rev Req	22,028,967	10,284,318	4,751,895		398,847	596,854		3,420,186		470,505		197,923	310,388	643,262	832,965
13	EX5-PS	Power Supply	Rev Req	15,869,178	10,284,318	4,751,895												832,965
14	EX5-TR	Transmission	Rev Req	398,847				398,847										
15	EX5-D	Distribution	Rev Req	5,760,941					596,854		3,420,186		470,505		197,923	310,388	643,262	

Summary of Classification Factors -- BUNDLED

Line No.	Name	Description	Source	Total	Residential (04-RS) Direct	GS Small (04-GSS) Direct	GS Small W/Space Heat (04-Rider 1) Direct	GS Large (04-GSL) Direct	GS Large W/Space Heat (04-Rider 1) Direct	Industrial (04-IS) Direct	Municipal Power (04-M-I) Direct	Water Pumping (04-WP) Direct	Irrigation (04-IP-I) Direct	Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I) Direct
		Classification Factor Data												
1	PROPLNT	Production Plant	Plant											
2	TRNPLNT	Transmission Plant	Plant	12,558,474										
3	DSTPLNT	Distribution Plant	Plant	40,497,347										735,348
4	PLNT	Prod, Trans, Dist. Subtotal	Plant	53,055,822										735,348
5	EX1	Assigned Dist. Oper. Exp.	Rev Req	959,855										
6	EX2	Assigned Dist. Main. Exp.	Rev Req	700,565										35,832
7	EX3	Dist. Oper. & Main.	Rev Req	2,049,818										36,903
8	EX4	Assigned O & M Exp.	Rev Req	17,821,706										36,903
9	EX4-PS	Power Supply	Rev Req	15,036,213										
10	EX4-TR	Transmission	Rev Req	92,413										
11	EX4-D	Distribution	**2,693,080**	2,693,080										36,903
12	EX5	Rev. Req. Less Margin	Rev Req	22,028,967										121,824
13	EX5-PS	Power Supply	Rev Req	15,869,178										
14	EX5-TR	Transmission	Rev Req	398,847										
15	EX5-D	Distribution	Rev Req	5,760,941										121,824

Summary of Classification Factors -- BUNDLED

Line No.	Name	Description	Source	Total	Power Supply Energy	Power Supply Cap.	Transmission Energy	Transmission Capacity	Dist. Substation Cap.	Dist. Substation Cons.	Primary Line Cap.	Primary Line Cons.	Line Transf. Cap.	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
16	**Classification Factors**																	
17	CACC	Consumer Accounting	Input	1.000000													1.000000	
18	CS	Customer Service	Input	1.000000													1.000000	
19	CS-PS	Cust. Service - Pwr. Supply	Input															
20	CS-TR	Cust. Service - Transmission	Input															
21	CS-D	Cust. Service - Distribution	Input	1.000000													1.000000	
22	SALES	Sales	Input	1.000000													1.000000	
23	SALES-PS	Sales - Power Supply	Input															
24	SALES-TR	Sales - Transmission	Input															
25	SALES-D	Sales - Distribution	Input	1.000000													1.000000	
26	PROPLNT	Production Plant	Plant															
27	TRNPLNT	Transmission Plant	Plant	1.000000				1.000000										
28	DSTPLNT	Distribution Plant	Plant	1.000000					0.140203		0.591627		0.152610		0.065147	0.032256		
29	PLNT	Prod, Trans, Dist. Subtotal	Plant	1.000000				0.236703	0.107016		0.451587		0.116486		0.049726	0.024621		
30	EX1	Assigned Dist. Oper. Exp.	Rev Req	1.000000							0.876980					0.123020		
31	EX2	Assigned Dist. Main. Exp.	Rev Req	1.000000					0.236873		0.634585		0.009509			0.067886		
32	EX3	Dist. Oper. & Main.	Rev Req	1.000000					0.083375		0.791661		0.003347			0.103614		
33	EX4	Assigned O & M Exp.	Rev Req	1.000000	0.577067	0.266635		0.005185	0.009590		0.091055		0.000385			0.011917	0.036094	
34	EX4-PS	Power Supply	Rev Req	0.843702	0.577067	0.266635												
35	EX4-TR	Transmission	Rev Req	0.005185				0.005185										
36	EX4-D	Distribution	Rev Req	0.151112					0.009590		0.091055		0.000385			0.011917	0.036094	
37	EX5	Rev. Req. Less Margin	Rev Req	1.000000	0.466854	0.215711		0.018106	0.027094		0.155259		0.021358		0.008985	0.014090	0.029201	0.037812
38	EX5-PS	Power Supply	Rev Req	0.720378	0.466854	0.215711												0.037812
39	EX5-TR	Transmission	Rev Req	0.018106				0.018106										
40	EX5-D	Distribution	Rev Req	0.261517					0.027094		0.155259		0.021358		0.008985	0.014090	0.029201	
41	EX6	A&G Classification	Input	1.000000					0.063460		0.602567		0.002548			0.078865	0.238857	
42	EX6-PS	Power Supply	Input															
43	EX6-TR	Transmission	Input															
44	EX6-D	Distribution	Input	1.000000					0.063460		0.602567		0.002548			0.078865	0.238857	
45	FUEL	Fuel	Input															
46	ICON	Install Cons. Prem.	Input	1.000000							1.000000							
47	LAND	Land & Land Rights	Input	1.000000					1.00000									
48	LICON	Leased Property	Input	1.000000							1.000000							
49	MTR	Meters	Input	1.000000												1.000000		
50	PRI	Primary Line	Input	1.000000							1.000000							
51	PROD1	Production Plant	Input															
52	PROD2	Production O & M	Input															
53	PURTR-1	Trans. Capacity	Input	1.000000				1.000000										
54	PURTR-2	Trans. Energy	Input	1.000000	1.000000													
55	PURKW-1	Purchased Power Capacity	Input	1.000000		1.000000												
56	PURKW-2	Summer	Input	1.000000		1.000000												
57	PURKW-3	Winter	Input	1.000000		1.000000												
58	PURKW-4	Other	Input	1.000000		1.000000												
59	PURKWH-1	Purchased Power Energy	Input	1.000000	1.000000													
60	PURKWH-2	On-Peak	Input	1.000000	1.000000													
61	PURKWH-3	Off-Peak	Input	1.000000	1.000000													
60	SERV	Services	Input	1.000000											1.000000			
61	STL	Street Lighting	Input															
62	SUB	Substation	Input	1.000000					1.000000									
63	TRAN1	Transmission Plant	Input	1.000000				1.000000										
64	TRAN2	Transmission Purchases	Input															
65	TRF	Line Transf.	Input	1.000000									1.000000					
66	REV	Revenue Related	Input	1.000000														1.000000
67	USER01	User Defined 01	Input															
68	USER02	User Defined 02	Input															
69	USER03	User Defined 03	Input															

Summary of Classification Factors -- BUNDLED

Line No.	Name	Description	Source	Total	Residential (04-RS) Direct	GS Small (04-GSS) Direct	GS Small W/Space Heat (04-Rider 1) Direct	GS Large (04-GSL) Direct	GS Large W/Space Heat (04-Rider 1) Direct	Industrial (04-IS) Direct	Municipal Power (04-M-I) Direct	Water Pumping (04-WP) Direct	Irrigation (04-IP-I) Direct	Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I) Direct
16	**Classification Factors**													
17	CACC	Consumer Accounting	Input	1.000000										
18	CS	Customer Service	Input	1.000000										
19	CS-PS	Cust. Service - Pwr. Supply	Input											
20	CS-TR	Cust. Service - Transmission	Input											
21	CS-D	Cust. Service - Distribution	Input	1.000000										
22	SALES	Sales	Input	1.000000										
23	SALES-PS	Sales - Power Supply	Input											
24	SALES-TR	Sales - Transmission	Input											
25	SALES-D	Sales - Distribution	Input	1.000000										
26	PROPLNT	Production Plant	Plant											
27	TRNPLNT	Transmission Plant	Plant	1.000000										
28	DSTPLNT	Distribution Plant	Plant	1.000000										0.018158
29	PLNT	Prod, Trans, Dist. Subtotal	Plant	1.000000										0.013860
30	EX1	Assigned Dist. Oper. Exp.	Rev Req	1.000000										
31	EX2	Assigned Dist. Main. Exp.	Rev Req	1.000000										0.051148
32	EX3	Dist. Oper. & Main.	Rev Req	1.000000										0.018003
33	EX4	Assigned O & M Exp.	Rev Req	1.000000										0.002071
34	EX4-PS	Power Supply	Rev Req	0.843702										
35	EX4-TR	Transmission	Rev Req	0.005185										
36	EX4-D	Distribution	Rev Req	0.151112										0.002071
37	EX5	Rev. Req. Less Margin	Rev Req	1.000000										0.005530
38	EX5-PS	Power Supply	Rev Req	0.720378										
39	EX5-TR	Transmission	Rev Req	0.018106										
40	EX5-D	Distribution	Rev Req	0.261517										0.005530
41	EX6	A&G Classification	Input	1.000000										0.013703
42	EX6-PS	Power Supply	Input											
43	EX6-TR	Transmission	Input											
44	EX6-D	Distribution	Input	1.000000										0.013703
45	FUEL	Fuel	Input											
46	ICON	Install Cons. Prem.	Input	1.000000										
47	LAND	Land & Land Rights	Input	1.000000										
48	LICON	Leased Property	Input	1.000000										
49	MTR	Meters	Input	1.000000										
50	PRI	Primary Line	Input	1.000000										
51	PROD1	Production Plant	Input											
52	PROD2	Production O & M	Input											
53	PURTR-1	Trans. Capacity	Input	1.000000										
54	PURTR-2	Trans. Energy	Input	1.000000										
55	PURKW-1	Purchased Power Capacity	Input	1.000000										
56	PURKW-2	Summer	Input	1.000000										
57	PURKW-3	Winter	Input	1.000000										
58	PURKW-4	Other	Input	1.000000										
59	PURKWH-1	Purchased Power Energy	Input	1.000000										
60	PURKWH-2	On-Peak	Input	1.000000										
61	PURKWH-3	Off-Peak	Input	1.000000										
60	SERV	Services	Input	1.000000										
61	STL	Street Lighting	Input											
62	SUB	Substation	Input	1.000000										
63	TRAN1	Transmission Plant	Input	1.000000										
64	TRAN2	Transmission Purchases	Input											
65	TRF	Line Transf.	Input	1.000000										
66	REV	Revenue Related	Input	1.000000										
67	USER01	User Defined 01	Input											
68	USER02	User Defined 02	Input											
69	USER03	User Defined 03	Input											

Summary of Allocation of Revenue Requirements to Rate Classes -- BUNDLED

Line No.	Cost Classification	Alloc. Factor	Total	Residential (04-RS)	GS Small (04-GSS)	GS Small W/Space Heat (04-Rider 1)	GS Large (04-GSL)	GS Large W/Space Heat (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)
1	**Power Supply**												
2	**Wholesale Power**												
3	Direct Assigned Charges (Credits)	Direct											
4	Demand Related	D7	4,751,895	2,383,799	234,738	14,305	1,845,161	86,737	96,240	3,006	25,334	9,240	53,334
5	Demand Related - Summer	D4											
6	Demand Related - Winter	D5											
7	Demand Related - Other	D6											
8	Subtotal - Demand		4,751,895	2,383,799	234,738	14,305	1,845,161	86,737	96,240	3,006	25,334	9,240	53,334
9	Energy Related	E1	10,284,318	4,792,033	437,533	22,736	4,400,400	150,168	250,115	4,250	46,185	13,876	167,022
10	Energy Related - On-Peak	E2											
11	Energy Related - Off-Peak	E3											
12	Subtotal - Energy		10,284,318	4,792,033	437,533	22,736	4,400,400	150,168	250,115	4,250	46,185	13,876	167,022
13	Revenue Related	R2											
14	Subtotal - Wholesale		15,036,213	7,175,833	672,271	37,041	6,245,561	236,905	346,354	7,255	71,519	23,116	220,356
15	**Allocated Overhead & Margin**												
16	Direct Related	Direct											
17	Revenue Related	R2											
18	Demand Related	D7											
19	Energy Related	E1											
20	Subtotal - Allocated												
21	Subtotal - Power Supply		15,036,213	7,175,833	672,271	37,041	6,245,561	236,905	346,354	7,255	71,519	23,116	220,356
22													
23	**Transmission**												
24	Direct Assigned	Direct											
25	Demand Related	D9	398,847	195,326	18,889	1,112	158,127	6,864	8,454	228	2,028	710	7,107
26	Energy Related	E1											
27	Subtotal--Transmission		398,847	195,326	18,889	1,112	158,127	6,864	8,454	228	2,028	710	7,107
28	**Allocated Overhead & Margin**												
29	Direct Related	Direct											
30	Revenue Related	R2											
31	Demand Related	D9											
32	Energy Related	E1											
33	Subtotal - Allocated												
34	Subtotal - Transmission		398,847	195,326	18,889	1,112	158,127	6,864	8,454	228	2,028	710	7,107
35													
36	**Distribution**												
37	Power Supply -Energy	E1											
38	Dist. Sub. -Capacity	D9	922,424	451,735	43,686	2,571	365,705	15,875	19,553	528	4,691	1,642	16,437
39	Dist. Sub. -Consumer	C2											
40	Primary Line -Capacity	D9	5,520,989	2,703,774	261,475	15,389	2,188,859	95,018	117,028	3,160	28,076	9,828	98,382
41	Primary Line -Consumer	C2											
42	Line Transf. -Capacity	D1	680,421	416,950	33,318	4,083	182,224	10,550	12,638	731	2,842	3,696	13,389
43	Line Transf. -Consumer	C3											
44	Sec. & Serv. -Consumer	C4	285,171	209,807	40,115	401	30,637	825	188	645	512	341	1,700
45	Meter -Consumer	C5	524,841	320,933	54,842	826	135,493	3,639	853	1,507	2,488	1,659	2,601
46	Acct. & Serv. -Consumer	C6	1,161,935	710,507	121,414	1,828	299,965	8,057	1,888	3,336	5,509	3,673	5,758
47	Revenue Related -Revenue	R1	832,965	441,181	35,191	(1,596)	286,021	5,748	11,947	573	2,440	3,156	48,304
48	Direct Assigned	Direct	146,142										146,142
49	Subtotal - Distribution		10,074,888	5,254,887	590,041	23,501	3,488,906	139,713	164,094	10,479	46,559	23,995	332,714
50	**Total**		25,509,948	12,626,046	1,281,201	61,654	9,892,594	383,483	518,902	17,963	120,106	47,821	560,177

Allocation of Plant in Service To Rate Classes -- BUNDLED

Line No.	Acct. No.	Description	Class. Factor	Total	Residential (04-RS)	GS Small (04-GSS)	GS Small W/Space Heat (04-Rider 1)	GS Large (04-GSL)	GS Large W/Space Heat (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)
1		**Intangible Plant**												
2	301	Organization	PLNT											
3	302	Franchises and consents	PLNT											
4	303	Miscellaneous intangible plant	PLNT											
5	301-303	Subtotal	PLNT											
6														
7		**Production Plant**												
8	310-346	Production Plant	PROD1											
9														
10		**Transmission Plant**												
11	350-359	Transmission Plant	TRAN1	12,558,474	6,299,989	620,375	37,806	4,876,456	229,232	254,346	7,943	66,954	24,421	140,953
12														
13		**Distribution Plant**												
14	360	Land	LAND	65,835	33,026	3,252	198	25,564	1,202	1,333	42	351	128	739
15	361	Structures	SUB											
16	362	Station	SUB	5,612,013	2,815,280	277,227	16,894	2,179,145	102,437	113,660	3,550	29,920	10,913	62,988
17	363	Battery	SUB											
18	364	Poles, towers	PRI	10,188,102	4,989,383	482,510	28,397	4,039,189	175,341	215,957	5,831	51,809	18,136	181,548
19	365	OH Cond	PRI	11,761,822	5,760,076	557,042	32,784	4,663,108	202,426	249,315	6,732	59,812	20,937	209,591
20	366	UG Conduit	PRI											
21	367	UG Cond	PRI	1,403,636	687,398	66,476	3,912	556,487	24,157	29,753	803	7,138	2,499	25,012
22	368	Transf	TRF	6,180,284	3,787,166	302,628	37,087	1,655,150	95,823	114,787	6,636	25,818	33,575	121,613
23	369	Services	SERV	2,638,271	1,941,036	371,124	3,708	283,443	7,632	1,740	5,964	4,736	3,157	15,730
24	370	Meters	MTR	1,306,289	798,777	136,498	2,055	337,232	9,058	2,122	3,751	6,193	4,129	6,473
25	371	Cons Premise	ICON	605,748	296,651	28,688	1,688	240,156	10,425	12,840	347	3,080	1,078	10,794
26	372	Leased Prop	LICON											
27	373	St. Light	STL	735,348										735,348
28	360-373	Subtotal		40,497,347	21,108,793	2,225,445	126,725	13,979,474	628,502	741,507	33,655	188,858	94,552	1,369,837
29														
30		**General Plant**												
31	389	Land & Land Rights	PLNT	116,500	60,184	6,249	361	41,404	1,883	2,187	91	562	261	3,317
32	390	Structures and Improve.	PLNT	1,922,880	993,365	103,140	5,963	683,388	31,086	36,092	1,508	9,271	4,312	54,755
33	391	Office Furniture & Equip.	PLNT	1,796,841	928,253	96,379	5,572	638,594	29,049	33,727	1,409	8,664	4,029	51,166
34	392	Transportation & Equipment	PLNT	1,156,596	597,501	62,038	3,587	411,052	18,698	21,709	907	5,577	2,594	32,935
35	393	Stores Equipment	PLNT	30,854	15,939	1,655	96	10,965	499	579	24	149	69	879
36	394	Tool, Shop & Garage Equip.	PLNT	261,649	135,169	14,034	811	92,990	4,230	4,911	205	1,262	587	7,451
37	395	Laboratory Equipment	PLNT	691,197	357,074	37,075	2,143	245,650	11,174	12,974	542	3,333	1,550	19,682
38	396	Power Operated Equipment	PLNT	996,223	514,652	53,436	3,089	354,056	16,106	18,699	781	4,803	2,234	28,368
39	397	Communication Equipment	PLNT	244,160	126,134	13,096	757	86,774	3,947	4,583	191	1,177	548	6,953
40	398	Miscellaneous Equipment	PLNT	5,782	2,987	310	18	2,055	93	109	5	28	13	165
41	399	Other tangible property	PLNT											
42	389-399	Subtotal		7,222,683	3,731,258	387,412	22,398	2,566,927	116,766	135,569	5,663	34,825	16,196	205,669
43														
44		**Total Plant**		60,278,505	31,140,040	3,233,232	186,929	21,422,857	974,500	1,131,421	47,262	290,637	135,169	1,716,459

Allocation of Revenue Requirements to Rate Classes -- BUNDLED

Line No.	Acct. No.	Description	Class. Factor	Total	Residential (04-RS)	GS Small (04-GSS)	GS Small W/Space Heat (04-Rider 1)	GS Large (04-GSL)	GS Large W/Space Heat (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)
1	**Power Supply**													
2		**Production**												
3	500-557	Fuel	FUEL											
4	500-557	Non-Fuel O&M - Demand	PROD1											
5	500-557	Non-Fuel O&M - Energy	PROD1											
6		Subtotal - Production												
7		**Purchases**												
8	555	Direct Assign. Chgs (Cr.)												
9	555	Substation Charges	PURSUB											
10	555	Demand Charges	PURKW-1	4,751,895	2,383,799	234,738	14,305	1,845,161	86,737	96,240	3,006	25,334	9,240	53,334
11	555	Summer	PURKW-2											
12	555	Winter	PURKW-3											
13	555	Other	PURKW-4											
14		Total Demand		4,751,895	2,383,799	234,738	14,305	1,845,161	86,737	96,240	3,006	25,334	9,240	53,334
15	555	Energy Charges	PURKWH-1	10,284,318	4,792,033	437,533	22,736	4,400,400	150,168	250,115	4,250	46,185	13,876	167,022
16	555	On-Peak	PURKWH-2											
17	555	Off-Peak	PURKWH-3											
18		Total Energy		10,284,318	4,792,033	437,533	22,736	4,400,400	150,168	250,115	4,250	46,185	13,876	167,022
19	555	Revenue Related Charges	REVENUE											
20		Subtotal - Purchases		15,036,213	7,175,833	672,271	37,041	6,245,561	236,905	346,354	7,255	71,519	23,116	220,356
21	500-557	Total Power Supply		15,036,213	7,175,833	672,271	37,041	6,245,561	236,905	346,354	7,255	71,519	23,116	220,356
22	**Transmission**													
23	560-573	Operation & Maintenance	TRAN1	92,413	45,257	4,377	258	36,638	1,590	1,959	53	470	165	1,647
24	555	Transmission - G&T Charges	TRAN2											
25		Total Transmission		92,413	45,257	4,377	258	36,638	1,590	1,959	53	470	165	1,647
26	**Distribution**													
27	580	Oper. Super & Eng.	EX1	351,055	177,179	19,093	926	133,207	5,598	6,596	300	1,770	685	5,700
28	581	Load Dispatch	EX1											
29	582	Oper. Station	SUB											
30	583	Oper. OH Line	PRI	800,483	392,018	37,911	2,231	317,360	13,777	16,968	458	4,071	1,425	14,264
31	584	Oper. UG Line	PRI	41,093	20,125	1,946	115	16,292	707	871	24	209	73	732
32	585	Oper. St. Lighting	STL											
33	586	Oper. Meters	MTR	118,082	72,205	12,339	186	30,484	819	192	339	560	373	585
34	587	Oper. Cons. Install	ICON	197	96	9	1	78	3	4	0	1	0	4
35	588	Oper. Misc. Oper.	EX1	17,413	8,788	947	46	6,607	278	327	15	88	34	283
36	589	Rents	EX1											
37	590	Main. Super. & Eng.	EX2											
38	591	Main. Structure	SUB	127	62	6	0	51	2	3	0	1	0	2
39	592	Main. Station	SUB	165,817	81,205	7,853	462	65,740	2,854	3,515	95	843	295	2,955
40	593	Main. OH Line	PRI	447,322	219,065	21,185	1,247	177,346	7,699	9,482	256	2,275	796	7,971
41	594	Main. UG Line	PRI	(2,754)	(1,349)	(130)	(8)	(1,092)	(47)	(58)	(2)	(14)	(5)	(49)
42	595	Main. Line Transf.	TRF	6,662	4,082	326	40	1,784	103	124	7	28	36	131
43	596	Main. St. Lighting	STL	35,832										35,832
44	597	Main. Meters	MTR	47,558	29,081	4,970	75	12,278	330	77	137	225	150	236
45	598	Main. Misc. Dist.	EX2	20,931	9,923	1,022	54	7,652	327	393	15	100	38	1,407
46	580-598	Subtotal		2,049,818	1,012,482	107,477	5,375	767,787	32,449	38,493	1,644	10,157	3,901	70,053

Allocation of Revenue Requirements to Rate Classes -- BUNDLED
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Residential (04-RS)	GS Small (04-GSS)	GS Small W/Space Heat (04-Rider 1)	GS Large (04-GSL)	GS Large W/Space Heat (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)
47		**Consumer Acct., Service & Sales**												
48		**Consumer Accounting**												
49	901	Supervision	CACC	26,050	15,929	2,722	41	6,725	181	42	75	124	82	129
50	902	Meter Reading Expense	CACC	369,835	226,149	38,645	582	95,477	2,565	601	1,062	1,753	1,169	1,833
51	903	Records & Collections	CACC	77,619	47,463	8,111	122	20,038	538	126	223	368	245	385
52	904	Uncollectible Accounts	CACC	147,084	89,940	15,369	231	37,971	1,020	239	422	697	465	729
53	905	Misc. Customer Account	CACC											
54		Subtotal		620,587	379,480	64,847	976	160,211	4,303	1,008	1,782	2,942	1,962	3,075
55		**Consumer Service & Info.**												
56	907	Supervision	CS											
57	908	Customer Assistance	CS											
58	909	Info. & Instruction	CS	20	12	2	0	5	0	0	0	0	0	0
59	910	Misc. Cust Serv. & Info	CS											
60		Subtotal		20	12	2	0	5	0	0	0	0	0	0
61		**Sales**												
62	911	Supervision	SALES											
63	912	Demonstrating & Selling	SALES											
64	913	Advertising	SALES	22,655	13,853	2,367	36	5,849	157	37	65	107	72	112
65	916	Misc. Sales	SALES											
66		Subtotal		22,655	13,853	2,367	36	5,849	157	37	65	107	72	112
67		**Prorated Operating Expenses**												
68		**Administrative & General**												
69	920	Administrative & General		272,486										
70	921	Office Supplies & Expenses		133,204										
71	922	Admin. Expenses Transferred		247,952										
72	923	Outside Services Employed		88,594										
73	924	Property Insurance		40,083										
74	925	Injuries & Damages		278,817										
75	926	Employee Pensions & Benefits		705,334										
76	927	Franchise Requirements												
77	928	Regulatory Commission Exp.		774										
78	929	Duplicate Charges		(104,561)										
79	930.1	General Advertising												
80	930.2	Misc.		122,813										
81	931	Rents												
82	935	Maint. of General Plant		51,160										
83		Accounts 920-935		1,836,655										
84		Power Supply	EX6-PS											
85		Transmission	EX6-TR											
86		Distribution	EX6-D	1,836,655	958,761	119,139	4,356	636,878	25,172	26,964	2,381	9,007	4,047	49,949
87		Subtotal - A&G		1,836,655	958,761	119,139	4,356	636,878	25,172	26,964	2,381	9,007	4,047	49,949

Allocation of Revenue Requirements to Rate Classes -- BUNDLED
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Residential (04-RS)	GS Small (04-GSS)	GS Small W/Space Heat (04-Rider 1)	GS Large (04-GSL)	GS Large W/Space Heat (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)
88	408	**Other Taxes**												
89		Power Supply	EX6-PS											
90		Transmission	EX6-TR											
91		Distribution	EX6-D	146,954	76,712	9,533	349	50,958	2,014	2,157	190	721	324	3,997
92		Subtotal - Other Taxes		146,954	76,712	9,533	349	50,958	2,014	2,157	190	721	324	3,997
93	421-	**Miscellaneous Expense**												
94	426,431	Power Supply	EX6-PS											
95		Transmission	EX6-TR											
96		Distribution	EX6-D	187,868	98,070	12,187	446	65,145	2,575	2,758	244	921	414	5,109
97		Subtotal - Misc. Expense		187,868	98,070	12,187	446	65,145	2,575	2,758	244	921	414	5,109
98	**Fixed Charges**													
99	403-	**Depreciation**												
100	407	Power Supply	PROPLNT											
101		Transmission	TRNPLNT	306,434	150,069	14,513	854	121,489	5,274	6,495	175	1,558	545	5,461
102		Distribution	DSTPLNT	1,355,581	704,315	74,106	4,200	469,491	20,840	25,000	1,115	6,275	3,134	47,107
103		Subtotal - Depreciation		1,662,015	854,384	88,618	5,054	590,980	26,114	31,496	1,291	7,833	3,679	52,567
104	408	**Property Taxes**												
105		Power Supply	REV											
106		Transmission	REV											
107		Distribution	REV	832,965	441,181	35,191	(1,596)	286,021	5,748	11,947	573	2,440	3,156	48,304
108		Subtotal - Property Taxes		832,965	441,181	35,191	(1,596)	286,021	5,748	11,947	573	2,440	3,156	48,304
109														
110		Total Oper. Expenses		22,488,163	11,056,026	1,116,009	52,293	8,846,032	337,028	463,174	15,477	106,119	40,836	455,170
111														
112	427	**Interest-LT**												
113		Power Supply	PROPLNT											
114		Transmission	TRNPLNT											
115		Distribution	DSTPLNT	1,682,525	874,184	91,979	5,212	582,724	25,866	31,030	1,384	7,788	3,889	58,468
116		Subtotal - Interest-LT		1,682,525	874,184	91,979	5,212	582,724	25,866	31,030	1,384	7,788	3,889	58,468
117		**Required Margin**												
118		Power Supply	PROPLNT											
119		Transmission	TRNPLNT											
120		Distribution	DSTPLNT	1,339,260	695,835	73,213	4,149	463,838	20,589	24,699	1,102	6,199	3,096	46,539
121		Subtotal - Required Margin		1,339,260	695,835	73,213	4,149	463,838	20,589	24,699	1,102	6,199	3,096	46,539
122	**Summary of Revenue Requirements**													
123		Power Supply		15,036,213	7,175,833	672,271	37,041	6,245,561	236,905	346,354	7,255	71,519	23,116	220,356
124		Transmission		398,847	195,326	18,889	1,112	158,127	6,864	8,454	228	2,028	710	7,107
125		Distribution		10,074,888	5,254,887	590,041	23,501	3,488,906	139,713	164,094	10,479	46,559	23,995	332,714
123		Total Rev. Req.		25,509,948	12,626,046	1,281,201	61,654	9,892,594	383,483	518,902	17,963	120,106	47,821	560,177

Rate Class Weighting Factors

I. Three Phase Vs. Single Phase Class Weighting Factors

A. Investment to Serve 3Ø vs. 1Ø Consumers (use replacement cost)

	1Ø	3Ø
1. kWh Meter	$90	$286
2. kWh & kW Meter	$233	$441
3. kWh & kW Meter (pulse activated)	$286	$546
4. Service [1]	$247	$409
5. Transformer [2]	$1,718	$2,751
6. Primary Line [3]	$714	$1,252

B. Weighting Factors for Relative 3Ø Class Investment Costs

1. Meter (3Ø Interval Recording)	$1,200	÷	$90	=	13.33
2. Meter (3Ø w/demand, TOD)	$546	÷	$90	=	6.07
3. Meter (3Ø w/demand)	$441	÷	$90	=	4.90
4. Meter (3Ø w/o demand)	$286	÷	$90	=	3.18
5. Meter (1Ø w/demand)	$233	÷	$90	=	2.59
6. Service	$409	÷	$247	=	1.65
7. Transformer	$2,751	÷	$1,718	=	1.60
8. Primary Line	$1,252	÷	$714	=	1.75

[1] Assume a typical installation of 80 feet of 1/0 triplex (or quadriplex), pole and miscellaneous materials to estimate the difference between a 1Ø and 3Ø installation.

[2] Use the cost difference between 1-75 kVA transformer and 3-25 kVA transformers as representative of the difference between a 1Ø versus a 3Ø transformer installation.

[3] Assume a typical installation of 150 feet of 1/0 ACSR to estimate the difference in primary line between a 1Ø and 3Ø installation.

Estimate of Class Demands Summary

Description	Total System	Residential (04-RS)	GS Small (04-GSS)	GS Small W/Space Heat (04-Rider 1)	GS Large (04-GSL)	GS Large W/Space Heat (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)	
Class Billing Determinants												
Number of Consumers	14,140	11,066	1,891	18	1,102	30	6	34	27	18	4,484	-
Energy (MWh)	233,865	108,971	9,949	517	100,065	3,415	5,688	97	1,050	316	3,798	-
Billing Demand (kW)	299,618	-	-	-	272,432	12,976	14,210	-	-	-	-	-
Estimated Demand Responsibility												
Non-Coincident Consumer Demand	188,266	115,366	9,219	1,130	50,420	2,919	3,497	202	786	1,023	3,705	n/a
Non-Coincident Class Demand	53,060	26,425	2,602	159	20,454	962	1,067	33	281	102	975	-
Coincident Class Demand - Ave. Monthly	43,425	21,784	2,145	131	16,862	793	879	27	232	84	487	-
Coincident Class Demand - Summer												
Coincident Class Demand - Winter												
Coincident Class Demand - Weighted	43,425	21,784	2,145	131	16,862	793	879	27	232	84	487	-
Coincident Class Demand - Transm.												
										56.8		

Estimate of Class Demands

Line No.	Description	Total System	Residential (04-RS)	GS Small (04-GSS)	GS Small W/Space Heat (04-Rider 1)	GS Large (04-GSL)	GS Large W/Space Heat (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)
1	**Non-Coincidental Class Demand - Average Monthly**											
2	Total System Sales (MWh)	233,865	108,971	9,949	517	100,065	3,415	5,688	97	1,050	316	3,798
3	Line Losses	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
4	kWh Purchased (MWh)	250,244	116,603	10,646	553	107,073	3,654	6,086	103	1,124	338	4,064
5	Divide by Hours	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760
6	Average Demand (kWh)	28,567	13,311	1,215	63	12,223	417	695	12	128	39	464
7												
8	Average Customers	18,676	11,066	1,891	18	1,102	30	6	34	27	18	4,484
9												
10	Calculated Maximum Demand [1]	52,234	26,425	2,602	159	18,918	789	1,701	33	281	102	1,223
11												
12	Substitutions											
13	Bary Curve Estimate (Max. Annual or Seas.) [2]		n/a	n/a	n/a	20,454	962	1,067	n/a	n/a	n/a	n/a
14	Other Substitutions [3]		n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	975
15	Non-Coincident Class Demand	53,060	26,425	2,602	159	20,454	962	1,067	33	281	102	975
16	**Sum of Non-Coincidental Demands of Individual Customers - Annual Peak**											
17	Peak Month Sales Data											
18	Peak Month		Jul-09	Dec-09	Jan-09	Jul-09	Dec-09	Jul-09	Jun-09	Aug-09	Jul-09	May-09
19	kWh Sales		14,009,536	1,014,197	371,119	10,632,803	472,972	526,766	23,069	109,118	154,770	463,375
20	Consumers		11,069	1,891	47	1,071	30	6	34	27	18	242
21	Sum of Individual Consumer's Non-coincident Demands [4]		115,368	9,221	948	71,113	2,915	2,665	204	786	1,023	67,435
22												
23	Substitute (from Historical Billing Records)		n/a	n/a	n/a	70,020	2,919	3,588	n/a	n/a	n/a	n/a
24	Non-Coincident Demand from Billing Records		n/a	n/a	n/a	378,336	12,976	14,580	n/a	n/a	n/a	n/a
25	Sum of Individual Customer Non-Coincident Peak Demands (Adjusted to Test Year) [5]		115,366	9,219	1,130	50,420	2,919	3,497	202	786	1,023	3,705

[1] The class diversified demand is calculated based on the formulas contained in RUS Demand Tables (Bulletin 45-2). The formula is a follows:

Class Diversified Demand = $L8 \times (1\text{-}0.4 \times L8 + 0.4 \times (L8^2 + 40)^{0.5}) \times (0.005925 \times (L4 \times 1{,}000 \div (L8 \times 12))^{0.885})$

[2] See "Annual Bary Curve Estimates"

[3] Security Lighting demand is calculated based on wattage, (including ballasts) number of lights and assumed annual hours of operation. Includes estimates for unmetered lights only.

[4] The sum of the Individual Consumers Non-coincident Demands is calculated using the RUS demand for a single customer multiplied by the Test Year number of customers.

Sum of Individual Consumer Demands = $(1\text{-}0.4 \times 1 + 0.4 \times (1^2 + 40)^{0.5}) \times (0.005925 \times (L19 \div L20)^{0.885})$

[5] Adjusted to Test Year conditions.

Estimate of Class Demands

Line No.	Description	Total System	Residential (04-RS)	GS Small (04-GSS)	GS Small W/Space Heat (04-Rider 1)	GS Large (04-GSL)	GS Large W/Space Heat (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)
26	**Annual Bary Curve Estimates**											
27	Sum of Monthly Non-Coincidental Demands for Test Year		-	-	-	272,432	12,976	14,210	-	-	-	-
28												
29	MWh Sales		-	-	-	100,065	3,415	5,688	-	-	-	-
30												
31	Load Factor (730 hours per month)					50.3%	36.0%	54.8%				
32												
33	Coincidence Factor (From Bary Curve)		n/a	n/a	n/a	84.2%	83.1%	84.2%	n/a	n/a	n/a	n/a
34												
35	Billing Months per Year		12	12	12	12	12	12	12	12	12	12
36												
37	Estimated Non-Coincidental Average Monthly Demand ((L2*L8)/L10)		n/a	n/a	n/a	19,116	899	997	n/a	n/a	n/a	n/a
38	Estimated Non-Coincidental Demand - Average Monthly (Including Line Loss)		n/a	n/a	n/a	20,454	962	1,067	n/a	n/a	n/a	n/a
39												
40	**Determination of Class Coincident Demand - Average Monthly**											
41	System Coincident Demand - Average Monthly (Per Exhibit II)	43,425										
42												
43	Coincidence Factors from Other Sources [1]		n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	50.00%
44	Average Monthly Non-Coincident Demand [2]		-	-	-	-	-	-	-	-	-	975
45	Coincident Demand - Direct Assigned	487	-	-	-	-	-	-	-	-	-	487
46												
47	Remaining Coincident Demand	42,937										
48	Remaining Non-Coincident Demand	52,086	26,425	2,602	159	20,454	962	1,067	33	281	102	-
49	Coincidence Factor for Remaining Classes [3]	82.4%	82.4%	82.4%	82.4%	82.4%	82.4%	82.4%	82.4%	82.4%	82.4%	
50	Coincident Demand for Remaining Classes		21,784	2,145	131	16,862	793	879	27	232	84	-
51	Coincident Demand - Ave. Monthly	43,425	21,784	2,145	131	16,862	793	879	27	232	84	487

Outdoor Lighting

A. Separately Metered Energy

kWh	-	
Ave. LF	48%	
		0
		0

Private Area / Street Lighting
A. Unmetered Lights

Size/Type	# of Lights	Power Required Per Light Lamp kW	Power Required Per Light Ballast kW	Power Required Per Light Total kW	Estimated Annual kWh/month	Estimated kWh	Total kW 1
100 W MV		0.100	0.035	0.135	45	-	0.0
175 W MV	1,796	0.175	0.035	0.210	75	1,616,400	377.2
250 W MV	82	0.250	0.050	0.300	107	105,288	24.6
400 W MV	130	0.400	0.050	0.450	173	269,880	58.5
1000 W MV	18	1.000	0.100	1.100	394	85,104	19.8
70 W HPS	47	0.070	0.025	0.095	34	19,176	4.5
100 W HPS	1,590	0.100	0.035	0.135	45	858,600	214.7
150 W HPS	182	0.150	0.050	0.200	68	148,512	36.4
200 W HPS	237	0.200	0.055	0.255	87	247,428	60.4
250 W HPS	161	0.250	0.060	0.310	108	208,656	49.9
400 W HPS	218	0.400	0.075	0.475	173	452,568	103.6
1000 W HPS	23	1.000	0.100	1.100	394	108,744	25.3
Total	4,484					4,120,356	975
Average monthly usage						76.58	0.217

Development of Allocation Factors -- BUNDLED

Line No.	Description	Units	Total	Residential (04-RS)	GS Small (04-GSS)	GS Small W/Space Heat (04-Rider 1)	GS Large (04-GSL)	GS Large W/Space Hea (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Lighting \L-SL-I, DOI (PAL-I, SL-I
1	**Allocation Factor Input Data**												
2	**Energy**												
3	Energy Sales -- All	MWh	233,865	108,971	9,949	517	100,065	3,415	5,688	97	1,050	316	3,798
4	Energy Sales -- On-Peak	MWh											
5	Energy Sales -- Off-Peak	MWh											
6	Dist. Losses	MWh	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
7	Energy -- All @ Sub.	MWh	250,244	116,603	10,646	553	107,073	3,654	6,086	103	1,124	338	4,064
8	Energy -- On-Peak @ Sub.	MWh											
9	Energy -- Off-Peak @ Sub.	MWh											
10	Trans. Losses	MWh											
11	Energy -- All @ Source	MWh	250,244	116,603	10,646	553	107,073	3,654	6,086	103	1,124	338	4,064
12	Energy -- On-Peak @ Source	MWh											
13	Energy -- Off-Peak @ Source	MWh											
14	**Demand**												
15	Non-Coinc. Demand @ Cons.	kW	188,266	115,366	9,219	1,130	50,420	2,919	3,497	202	786	1,023	3,705
16	Class Non-Coinc. Demand @ Sub.	kW	53,060	26,425	2,602	159	20,454	962	1,067	33	281	102	975
17	Class Non-Coinc. Demand Transm.	kW											
18	Summer Coinc. Demand	kW											
19	Winter Coinc. Demand	kW											
20	Other Coinc. Demand	kW											
21	Coinc. Demand @ Sub.	kW	43,425	21,784	2,145	131	16,862	793	879	27	232	84	487
22	Coinc. Demand @ Source	kW	43,425	21,784	2,145	131	16,862	793	879	27	232	84	487
23	**Average and Excess Demand**												
24	Average Demand	kW	28,567	13,311	1,215	63	12,223	417	695	12	128	39	464
25	Class Excess Demand	kW	24,494	13,115	1,387	95	8,231	544	372	22	153	64	511
26	Allocated Excess Demand	kW	14,858	7,955	841	58	4,993	330	226	13	93	39	310
27	Avg. & Excess Demand	kW	43,425	21,266	2,057	121	17,216	747	920	25	221	77	774
28	**Margin**												
29	Present Rate Margin	$	5,604,650	2,968,511	236,783	(10,741)	1,924,509	38,678	80,386	3,854	16,421	21,232	325,018
30	Proposed Rate Revenue	$	21,039,710	10,339,670	927,943	27,412	8,328,197	282,448	435,195	11,337	89,968	45,059	552,482
31	**Consumer**												
32	No. Consumers		18,676	11,066	1,891	18	1,102	30	6	34	27	18	4,484
33	Pri. Line Weight. Factor			1.00	1.14	1.20	1.54	1.52	1.75	1.00	1.00	1.00	0.02
34	Weight. No. of Cons.		15,159.4	11,066.0	2,150.9	21.6	1,696.1	45.6	10.5	34.0	27.0	18.0	89.7
35	Transf. Weight. Factor			1.00	1.11	1.16	1.43	1.41	1.60	1.00	1.00	1.00	0.02
36	Weight. No. of Cons.		14,980.9	11,066.0	2,098.0	20.9	1,575.2	42.4	9.6	34.0	27.0	18.0	89.7
37	Service Weight. Factor			1.00	1.12	1.17	1.47	1.45	1.65	1.00	1.00	1.00	0.02
38	Weight. No. of Cons.		15,041.0	11,066.0	2,115.8	21.1	1,615.9	43.5	9.9	34.0	27.0	18.0	89.7
39	Meter Weight. Factor			1.00	1.00	1.58	4.24	4.18	4.90	1.53	3.18	3.18	0.02
40	Weight. No. of Cons.		18,096.9	11,066.0	1,891.0	28.5	4,671.9	125.5	29.4	52.0	85.8	57.2	89.7
41	Cons. Acct. Weight Factor			1.00	1.00	1.58	4.24	4.18	4.90	1.53	3.18	3.18	0.02
42	Weight. No. of Cons.		18,096.9	11,066.0	1,891.0	28.5	4,671.9	125.5	29.4	52.0	85.8	57.2	89.7

Development of Allocation Factors – BUNDLED
(Continued)

Line No.	Description	Data Line No.	Name	Total	Residential (04-RS)	GS Small (04-GSS)	GS Small W/Space Heat (04-Rider 1)	GS Large (04-GSL)	GS Large W/Space Hea (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Lighting \L-SL-I, DOI (PAL-I, SL-I
43	**Allocation Factors**													
44	**Energy Related**													
45	Energy -- All @ Sub.	7	E1	1.000000	0.465955	0.042544	0.002211	0.427875	0.014602	0.024320	0.000413	0.004491	0.001349	0.016240
46	Energy -- On-Peak @ Sub.	8	E2											
47	Energy -- Off-Peak @ Sub.	9	E3											
48	Energy -- All @ Source	11	E4	1.000000	0.465955	0.042544	0.002211	0.427875	0.014602	0.024320	0.000413	0.004491	0.001349	0.016240
49	Energy -- On-Peak @ Source	12	E5											
50	Energy -- Off-Peak @ Source	13	E6											
51														
52	**Demand Related**													
53	Non-coinc. Demand @ Cons.	15	D1	1.000000	0.612782	0.048967	0.006001	0.267811	0.015505	0.018573	0.001074	0.004178	0.005433	0.019678
54	Non-coinc. Demand @ Class	16	D2	1.000000	0.498026	0.049042	0.002989	0.385493	0.018121	0.020107	0.000628	0.005293	0.001931	0.018371
55	Non-coinc. Demand @ Transm	17	D3											
56	Summer Coinc. Demand	18	D4											
57	Winter Coinc. Demand	19	D5											
58	Other Coinc. Demand	20	D6											
59	Coinc. Demand @ Sub.	21	D7	1.000000	0.501652	0.049399	0.003010	0.388300	0.018253	0.020253	0.000633	0.005331	0.001945	0.011224
60	Coinc. Demand @ Source	22	D8	1.000000	0.501652	0.049399	0.003010	0.388300	0.018253	0.020253	0.000633	0.005331	0.001945	0.011224
61	Avg. & Excess	27	D9	1.000000	0.489726	0.047360	0.002787	0.396461	0.017210	0.021197	0.000572	0.005085	0.001780	0.017820
62	Avg. & Excess (w/o Enbridge)	28	D10	1.000000	0.489726	0.047360	0.002787	0.396461	0.017210	0.021197	0.000572	0.005085	0.001780	0.017820
62														
63	**Revenue Related**													
64	Present Rate Margin	29	R1	1.000000	0.529651	0.042248	-0.001917	0.343377	0.006901	0.014343	0.000688	0.002930	0.003788	0.057991
65	Proposed Rate Revenue	30	R2	1.000000	0.491436	0.044104	0.001303	0.395832	0.013425	0.020684	0.000539	0.004276	0.002142	0.026259
66														
67	**Consumer Related**													
68	No. of Cons.	32	C1	1.000000	0.592525	0.101253	0.000964	0.059006	0.001606	0.000321	0.001821	0.001446	0.000964	0.240094
69	Pri. Line Weight. Cons.	34	C2	1.000000	0.729978	0.141883	0.001427	0.111882	0.003009	0.000695	0.002243	0.001781	0.001187	0.005916
70	Transf. Weight. Cons.	36	C3	1.000000	0.738676	0.140046	0.001395	0.105150	0.002833	0.000641	0.002270	0.001802	0.001202	0.005986
71	Services Weight. Cons.	38	C4	1.000000	0.735723	0.140669	0.001406	0.107435	0.002893	0.000659	0.002260	0.001795	0.001197	0.005962
72	Meter Weight. Cons.	40	C5	1.000000	0.611486	0.104493	0.001573	0.258160	0.006934	0.001625	0.002871	0.004741	0.003161	0.004956
73	Cons. Acct. Weight. Cons.	42	C6	1.000000	0.611486	0.104493	0.001573	0.258160	0.006934	0.001625	0.002871	0.004741	0.003161	0.004956