2009.03.02 13:55:59
Kansas Corporation Commission
/S/ Susan K. Duffy

Power System
Engineering, Inc.

OFFICES IN:

MADISON, WI
MINNEAPOLIS, MN
DES MOINES, IA
INDIANAPOLIS, IN

12301 Central Avenue, N.E., Suite 250
Blaine, MN 55434
Telephone: 763-755-5122
Fax: 763-755-7028
Web: www.powersystem.org

Via e-mail and UPS

February 27, 2009

STATE CORPORATION COMMISSION

MAR 0 2 2009

Susan K. Duffy

Ms. Susan Duffy, Executive Director
Kansas Corporation Commission
1500 Southwest Arrowhead Road
Topeka, KS 66604

Subject: Wheatland Electric Cooperative, Inc.
Application for Revised Rates, Tariffs, Rate Design Changes

Dear Ms. Duffy:

On December 23, 2008, the Wheatland Electric Cooperative, Inc. (Wheatland) Board of Trustees approved a resolution to authorize a rate filing with the Kansas Corporation Commission (KCC). The overall effect is a requested rate increase of $7,771,310 or 12.3 percent.

K.A.R.82-1-231a(a) affords any rural electric distribution cooperative with memberships of fewer than 15,000 to prepare a less extensive application than that outlined and required by 82-1-231. As of December 2008, Wheatland had 9,491 memberships and is thereby electing to make this rate application under 82-1-231a.

In support of this application, Wheatland submits the following information:

- Verification.
- Certification.
- Board Resolution.
- Public Meeting Notice.
- Prefiled Direct Testimony, Exhibits and Workpapers of Richard J. Macke:
  - Exhibit __(RJM-1) - Curriculum Vitae - Richard J. Macke.
  - Exhibit __(RJM-2) - Statement of Operations - Present Rates.
  - Exhibit __(RJM-3) - Revenue Requirements.
  - Exhibit __(RJM-4) - Cost of Service Analysis.
  - Exhibit __(RJM-5) - Statement of Operations - Proposed Rates.
  - Exhibit __(RJM-6) - Comparison of Present and Proposed Rate Schedules.
  - Exhibit __(RJM-7) - Comparison of Monthly Bills.

- Exhibit __(RJM-8) - Comparison of Phase 2 Proposed Rates.
- Exhibit __(RJM-9) - Present Rate Schedules
- Exhibit __ (RJM-10) - Present Rate Schedules with Redline Proposed
- Changes.
- Exhibit __(RJM-11) - Proposed Rate Schedules.
- Workpapers (A-L).

On December 12, 2008, Wheatland submitted a letter to the KCC, pursuant to K.A.R.82-1-231a, indicating our intention to file a rate application not less than 30 or more than 90 days from the date of this written notice.

On September 2, 2008 and in subsequent phone discussions, Wheatland representatives met with KCC technical staff for an initial review of the requirements and expectations for this rate application.

We look forward to working with your staff and implementing our proposed rate changes as soon as practical. If you or your staff have any questions regarding this rate application, please call me at (763) 755-5122.

Very truly yours,

Richard J. Macke
mmc

Richard J. Macke, Leader
Rates and Financial Planning
Power System Engineering, Inc.
12301 Central Avenue, N.E., Suite 250
Blaine, MN 55434

On behalf of:
Wheatland Electric Cooperative, Inc.
P.O. Box 230, 101 Main Street
Scott City, KS 67871

KS0510801/mmc

cc: Neil K. Norman, Wheatland Electric Cooperative, Inc.

Enclosures

VERIFICATION

STATE OF KANSAS)
) ss:
COUNTY OF SHAWNEE

Neil K. Norman, being first duly sworn, deposes and states that he is Manager, Wheatland Electric Cooperative, Inc., applicant in the above-captioned matter; that he has read the foregoing Application and verifies that the allegations therein contained are true to the best of his knowledge, information and belief.

Neil K. Norman

Subscribed and sworn to before me on this 27TH day of FEBRUARY 2009.

VINCENT J. STRICKLER
Notary Public - State of Kansas
My Appt. Expires 07/10/12

Notary Public

My Appointment Expires: JULY 10, 2012

CERTIFICATE OF SERVICE

I hereby certify that on this 27th day of February, 2009, a true and correct copy of the above and foregoing Application with all supporting schedules was sent overnight by United Parcel Service, properly addressed to:

Ms. Susan Duffy, Executive Director
Kansas Corporation Commission
1500 Southwest Arrowhead Road
Topeka, KS 66604

Marilyn M. Cuellar

Marilyn M. Cuellar
Project Assistant
Power System Engineering, Inc.

BOARD RESOLUTION

WHEREAS, Wheatland Electric Cooperative, Inc. has retained Power System Engineering, Inc. to conduct a review of the Cooperative's revenue requirements and cost of providing service to rate classes; and

WHEREAS, this review shows that Wheatland Electric Cooperative, Inc. needs to increase annual revenues in order to maintain its financial health and adequate cash position.

NOW, THEREFORE, BE IT RESOLVED, that Wheatland Electric Cooperative, Inc.'s rates be adjusted as shown on the attached Exhibit A; and

BE IT FURTHER RESOLVED, that Wheatland Electric Cooperative, Inc.'s General Manager is authorized to file the necessary documents with the Kansas Corporation Commission to implement these rates as soon as practical.

CERTIFICATION

I, Edwin Wasinger, Secretary of Wheatland Electric Cooperative, Inc., do hereby certify that the above Resolution was adopted at the regular meeting of the Board of Trustees of Wheatland Electric Cooperative, Inc., held in Scott City, Kansas, on December 23, 2008.

Secretary

Seal

WHEATLAND ELECTRIC

A Touchstone Energy® Cooperative

Notice of Public Meeting

Wheatland Electric Cooperative, Inc. plans to file an application with the Kansas Corporation Commission to increase its electric rates. The amount of the proposed increase is $7.8 million and, if granted in full, would result in an average increase of 12.2%. Comparisons of current revenues and proposed revenues and current rates and proposed rates can be found on the reverse side of this notice.

The proposed rate increase would include a Power Cost Adjustment (PCA) that would allow Wheatland to pass through changes in wholesale power costs from Sunflower, our power supplier, on a monthly basis.

A public meeting will be held to provide specific information at the following time and place:

Tuesday, February 24, 2009 at 1:00 p.m.
William H. Carpenter Building @ Scott County Fairgrounds

Members may submit written comments to the following address:

Rate Filing Comments
Wheatland Electric Cooperative, Inc.
P.O. Box 230
Scott City Kansas 67871

If you have any questions, please feel free to call Wheatland's office at (620) 872-5885 or 1-800-762-0436. Ask for Lynn Freese or Neil Norman.

More information on reverse side

101 Main Street
(620)-872-5885
P.O. Box 230
Toll Free (800)-762-0436
E-mail electric@weci.net
Scott City, Kansas 67871
Fax (620)-872-7170

Comparison of Revenue
Present and Proposed Rates

(a) Line No.	(b) Rate Class	(c) Revenue Present Rates	(d) Revenue Proposed Rates	(e) Increase (Decrease) Amount	(f) Increase (Decrease) Percent
		($)	($)	($)	(%)
1	Residential (88-D) [1]	9,892,374	11,101,970	1,209,596	12.2%
2	General Service (88-GS) [1]	15,671,270	19,744,779	4,073,508	26.0%
3	General Service Large (88-GSL)	4,579,359	5,648,610	1,069,251	23.3%
4	Municipal Power Service (88-M)	447,512	548,340	100,828	22.5%
5	Irrigation (96-IR) [1]	3,281,860	4,526,468	1,244,608	37.9%
6	Transmission Level Service (2007-TRANSERV-I)	27,753,226	27,753,226	-	0.0%
7	Other Contract Rates	1,383,879	1,383,879	-	0.0%
8	Lighting	355,090	447,896	92,806	26.1%
9	**Total**	63,364,571	71,155,168	7,790,598	12.3%

[1] Includes increases proposed to occur in second phase of increase (2010).

Comparison of Average Rate
Present and Proposed Rates

(a) Line No.	(b) Rate Class	(c) Energy Sales	(d) Average Rate Present	(e) Average Rate Proposed	(f) Increase (Decrease)
		(kWh)	(¢/kWh)	(¢/kWh)	(%)
1	Residential (88-D) [1]	90,080,595	10.98	12.32	12.2%
2	General Service (88-GS) [1]	150,743,068	10.40	13.10	26.0%
3	General Service Large (88-GSL)	57,168,879	8.01	9.88	23.3%
4	Municipal Power Service (88-M)	4,611,207	9.70	11.89	22.5%
5	Irrigation (96-IR) [1]	40,014,503	8.20	11.31	37.9%
6	Transmission Level Service (2007-TRANSERV-I)	426,396,830	6.51	6.51	0.0%
7	Other Contract Rates	21,046,916	6.58	6.58	0.0%
8	Lighting	2,311,203	15.36	19.38	26.1%
9	**Total**	792,373,201	8.00	8.98	12.3%

[1] Includes increases proposed to occur in second phase of increase (2010).

Comparison of Average Rate
Present and Proposed Rates

(a) Line No.	(b) Rate Class	(c) Ave. No. Consumers	(d) Average Bill Per Cons. Present	(e) Average Bill Per Cons. Proposed	(f) Increase (Decrease)
		(cons.)	($/cons./mo.)	($/cons./mo.)	($/cons./mo.)
1	Residential (88-D) [1]	9,150	90.09	101.11	12.2%
2	General Service (88-GS) [1]	7,157	182.47	229.90	26.0%
3	General Service Large (88-GSL)	47	8,119.43	10,015.27	23.3%
4	Municipal Power Service (88-M)	112	332.97	407.99	22.5%
5	Irrigation (96-IR) [1]	867	315.44	435.07	37.9%
6	Transmission Level Service (2007-TRANSERV-I)	3	770,922.93	770,922.93	0.0%
7	Other Contract Rates	2	57,661.63	57,661.63	0.0%
8	Lighting	130	227.62	287.11	26.1%
9	**Total**	17,468	302.29	339.45	12.3%

[1] Includes increases proposed to occur in second phase of increase (2010).

STATE CORPORATION COMMISSION

MAR 0 2 2009

Susan Talbott

STATE OF KANSAS

BEFORE THE KANSAS CORPORATION COMMISSION

Application for Revised Rates, Tariffs, and Rate Design Changes

of

Wheatland Electric Cooperative, Inc

Docket No. 09-WHLE-681-RTS

February 27, 2009

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

ON BEHALF OF
WHEATLAND ELECTRIC COOPERATIVE, INC.

STATE CORPORATION COMMISSION

MAR 0 2 2009

Susan Talbott

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BEFORE THE KANSAS CORPORATION COMMISSION

Application for Revised Rates, Tariffs, and Rate Design Changes

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RICHARD J. MACKE
LEADER, RATES AND FINANCIAL PLANNING
POWER SYSTEM ENGINEERING, INC.

ON BEHALF OF
WHEATLAND ELECTRIC COOPERATIVE, INC.

PART I - QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Richard J. Macke. My business address is 12301 Central Avenue, N.E., Suite 250, Blaine, Minnesota 55434.

Q. What is your profession?

A. I lead the Rate and Financial Planning department at Power System Engineering, Inc. ("PSE"), which is headquartered at 2000 Engel Street, Suite 100, 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 is in Madison, Wisconsin with regional offices in Indianapolis, Indiana; Minneapolis, Minnesota; and Marietta, OH. PSE is involved in: power supply and system planning; distribution, substation and transmission design; construction contracting and supervision; retail and wholesale rate and cost of service ("COS") studies; load management and other economic feasibility studies; load forecasting; financial and operating consultation; telecommunication and network design, mapping/GIS; and system automation including SCADA/EMS, SCADA/DMS, metering, substation automation, distribution automation and outage management systems.

Q. Please describe your responsibilities with Power System Engineering, Inc.

A. I lead PSE's Rates and Financial Planning Department. This department includes staff in Minnesota and Indiana that provides services predominantly for electric cooperative and municipal utilities such as:

- 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, with an emphasis in Finance and Marketing. In 2007, I received my Master 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 Power System Engineering, Inc. in Blaine, Minnesota as a Financial Analyst in the Utility Planning and Rates Division. My emphasis was on retail rate studies, including revenue requirements and bundled/unbundled cost of service studies. I also provided analysis used to support testimony, mergers and acquisitions cases 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 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. I also provided general financial, management and public policy support to clients.

I have been employed from 1999 to Present by Power System Engineering, Inc. in Blaine, Minnesota. From 1999 to 2002, I held the position of Rate and Financial Analyst in the Rates and Financial Planning Division. Emphasis was on performing complex financial analyses, such as rate studies consisting of determination of revenue requirements, bundled and unbundled cost of service analysis and rate design. Other responsibilities included performing analysis of special rates and programs, key account analyses, financial forecasting, activity-based costing, policy development and evaluation and other financial analyses for various PSE clients. From 2002 to March 2008, I held the position of Senior Rate and Financial Analyst in the Utility Planning and Rate Division. My responsibilities included 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 included strategic planning, litigation support, regulatory compliance, capital expenditure and operational assessments and advisement. From April 2008 to Present, I have held the position of Leader, Rates and

Financial Planning. In this capacity, I continue to provide rate and financial consulting services to clients in addition to managing the Rates and Financial Planning department.

Q. Please summarize your educational and work experience.

A. A copy of my curriculum vitae is provided as Exhibit __(RJM-1).

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

A. Yes. I recently submitted testimony on behalf of Pioneer Electric Cooperative in docket No. 09-PNRE-563-RTS.

Q. Have you submitted testimony to other state regulatory commissions?

A. Yes. I have submitted testimony to the regulatory commissions in Minnesota and Texas.

Q. Do you have any other rate related experience?

A. Yes. I have personally directed well over 100 rate study efforts. While in many cases these rate studies were conducted for self-regulated electric cooperatives, I have also performed such analysis that was ultimately filed in regulated rate cases on behalf of cooperatives in Iowa, Kansas, Michigan, Minnesota and New Hampshire.

PART II - PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to present the analysis of Wheatland Electric Cooperative, Inc.'s ("Wheatland" or "Cooperative") revenue requirements, class cost of service study and proposed rates within the context of the January-December 2007 Historical Test Year adjusted for known and measurable changes.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit __(RJM-1) - Curriculum Vitae - Richard J. Macke.
Exhibit __(RJM-2) - Statement of Operations - Present Rates.
Exhibit __(RJM-3) - Revenue Requirements.
Exhibit __(RJM-4) - Cost of Service Analysis.
Exhibit __(RJM-5) - Statement of Operations - Proposed Rates.
Exhibit __(RJM-6) - Comparison of Present and Proposed Rate Schedules.
Exhibit __(RJM-7) - Comparison of Monthly Bills.
Exhibit __(RJM-8) - Comparison of Phase 2 Proposed Rates.
Exhibit __(RJM-9) - Present Rate Schedules.
Exhibit __(RJM-10) - Present Rate Schedules with Redline Proposed Changes.
Exhibit __(RJM-11) - Proposed Rate Schedules.

Q. Please identify the documents included in the workpapers you have submitted:

A. The workpapers include the following documents:

A) Form 7 - January-December 2007.
B) Load Data.
C) Load Data - GS, LG-IND, Contracts.
D) Lighting Counts.
E) Summary and Detail of Wheatland Purchased Power (January-December 2007).
F) Adjustment for Known and Measurable Changes.
G) Board Policy No. 37 - Equity Level, Financial Ratios and Patronage Capital Goals and Plans.
H) Plant and Expense Account Data (January-December 07).
I) Single Phase and Three Phase Counts.
J) Wheatland Notice of Intent to File - December 12, 2008.

K) Wheatland Board Resolution.
L) Wheatland Public Meeting Notice.

Q. Has the material included in your exhibits and workpapers been prepared by you or by others under your direction?

A. Yes, it was.

PART III - SUMMARY OF FILING

Q. What are Wheatland's objectives in filing this rate application?

A. Wheatland has three primary objectives in filing this rate application. The first objective is financial. Wheatland has been and will be incurring significant cost increases which make an increase in rates necessary and unavoidable. This rate application will allow the Cooperative to increase operating revenues and achieve acceptable financial operating results. The second objective of this rate application is to make rate design adjustments to ensure fair recovery of costs by rate class and rate components. The Cooperative's last general rate application was in 1987-88, and much has changed concerning certain customer classes and cost structures. The third objective is to implement a Power Cost Adjustment (PCA) that will allow Wheatland to track revenue with future changes in power costs without the need for rate applications.

Q. Would you please summarize the revenue requirement, COS study results and proposed rate design results contained in your testimony?

A. <u>Revenue Requirements -- Summary</u>

The revenue requirements of the Cooperative simply refer to the total cost of doing business and are comprised of operating expenses plus margin requirements. By comparing the revenue requirements against present revenue, the adequacy of the present rates can be assessed; and a general change in rates can be discussed.

Operating expenses for the Cooperative (excluding interest) total $63,560,795. We have used a Times Interest Earned Ratio (TIER) of 2.20 to determine the adequacy of present rates. The result is a required revenue increase of $7,771,310 or 12.3 percent. Table 1 presents a summary of revenue requirements analysis for the Test Year.

Table 1
Revenue Requirements Summary
Method B - TIER = 2.20 Objective

			($)
1.	Operating Expenses (Excluding Interest)		63,560,795
2.	Margin Requirements		
	a. Interest expense		4,650,000
	b. Target TIER		2.20
	c. Total Margin Requirements (Before Interest)		10,230,000
	d. Less: Capital Credits		1,016,185
	e. Less: Non-Operating Income		1,192,548
	f. Net Operating Income Required		8,021,267
3.	Total Revenue Requirements		71,582,062
4.	Revenue From Present Rates		
	a. Tariff Revenue		63,364,571
	b. Other Operating Revenue		446,181
	c. Total Revenue		63,810,752
5.	Required Increase (Decrease)		7,771,310
		or	12.26%

Class Cost of Service -- Summary

PSE performed a class COS analysis which is included in the attached Exhibit __(RJM-4). This analysis was aimed at identifying the cost responsibility of each rate class. The COS is also useful in determining the cost components of each rate class (i.e. customer, energy and demand costs). The results of the class COS analysis are summarized in the following Table 2.

Table 2
Cost of Service Summary

Rate Class	Revenue Present Rates[1]	Revenue Requirement	Increase (Decrease) Amount	Increase (Decrease) Percent[2]
	($)	($)	($)	(%)
Residential (88-D)	9,786,357	10,903,975	1,117,618	11.6
Domestic Base Monthly (88-DBMC)	84,623	110,995	26,372	31.6
Non-Domestic Rural (NDR)	112,844	140,136	27,292	24.5
Municipal Power (88-M)	453,376	554,432	101,055	22.6
Gen. Serv. (88-GS)	12,174,047	14,838,458	2,664,411	22.2
Gen. Serv. Base Monthly (92-GSBMC)	1,076,756	1,501,587	424,831	40.0
Gen. Serv. TOD (96-GSTOD)	2,483,167	3,109,865	626,698	25.6
Gen. Serv. Large (88-GSL)	268,825	282,353	13,528	5.1
GS Lg. Base Monthly (92-GSLBMC)	517,230	668,677	151,446	29.7
Gen. Serv. Lg. TOD (96-GSLTOD)	3,853,312	4,692,016	838,705	22.1
Irrigation (96-IR)	3,324,866	4,980,541	1,655,675	50.4
Athletic Field Lighting (88-AF)	15,609	17,712	2,103	13.6
Street & Area Lighting (88-PSL)	175,122	231,523	56,401	32.6
(91-SL)	169,012	234,187	65,175	39.1
Total[3]	34,495,148	42,266,457	7,771,310	22.5

As the above table illustrates, there are presently some cross subsidies between the rate classes with respect to cost recovery. It is important, at this point, to distinguish between the COS and actual rate design. Due to the limitations inherent to a COS analysis, these results should be viewed as providing a general range of where rates should be. It is, in fact, uncommon for rates to be designed exactly in line with COS results.

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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 cost of service excludes rate classes or consumers which are served under contract rates or cost plus rates.

Proposed Rates -- Summary

Using the previously completed COS analysis, and in conjunction with Wheatland management and Trustees, proposed rates were developed. These rates are designed to meet various objectives of Wheatland and are discussed later in my testimony. Table 3 summarizes the impact of the proposed rates on Wheatland's rate revenue by class.

Table 3
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 (88-D)	9,659,775	10,818,004	1,158,229	12.0
2	Domestic Base Monthly Charge (88-DBMC)	83,529	105,353	21,824	26.1
3	Domestic Cooling & Heating (88-DCH)	149,071	175,015	25,944	17.4
4	General Service (88-GS)	12,016,580	14,892,278	2,875,698	23.9
5	General Service Cooling & Heating (88-GSCH)	29,428	33,999	4,570	15.5
6	General Service Large (88-GSL)	265,348	285,719	20,371	7.7
7	Municipal Power Service (88-M)	447,512	548,340	100,828	22.5
8	Non-Domestic Rural (88-NDR)	111,384	129,565	18,180	16.3
9	Private Street & Area Lighting (88-PSL)	172,857	218,907	46,049	26.6
10	Gen. Serv. Lg. Base Mo. Charge (92-GSBMC)	510,540	644,263	133,723	26.2
11	Lg. Industrial Interruptible (LG-IND)	495,661	495,661	-	0.0
12	Public Street Lighting (91-SL)	166,826	210,706	43,880	26.3
13	Athletic Field Lighting (88-AF)	15,408	18,284	2,877	18.7
14	Gen. Serv. Base Mo. Charge (92-GSBMC)	1,062,829	1,360,964	298,135	28.1
15	Gen. Serv. Lg. TOD (96-GSLTOD)	3,803,470	4,718,628	915,158	24.1
16	Gen. Serv. TOD (96-GSTOD)	2,451,048	3,071,722	620,674	25.3
17	Irrigation (96-IR)	3,281,860	4,138,638	856,777	26.1
18	Transmission Level Service (25 MW)	15,770,401	15,770,401	-	0.0
19	SP Contract (LAKIN)	888,218	888,218	-	0.0
20	Transmission Level Service (5MW)	11,982,825	11,982,825	-	0.0
21	Total	63,364,571	70,507,488	7,142,917	11.3

Because of the desire to eliminate the Base Monthly Charge rates and the impact of achieving such, Wheatland is proposing a second phase to the rate change for those rates. Similarly, in order to achieve the desired result for the Irrigation rate, Wheatland is proposing a second phase for that rate class also. The second phase rate increases would be effective 12 months subsequent to the effective date of the changes illustrated in the above Table 3. Table 4 illustrates the impact of the Phase 2 proposed rates by rate class.

Table 4
Comparison of Revenue
Present and Proposed Rates (Phase 2)

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	**Rate Class**	**Revenue Present Rates**	**Revenue Proposed Rates**	**Increase (Decrease) Amount**	**Percent**
		($)	($)	($)	(%)
1	Domestic Base Monthly Charge (88-DBMC)	105,353	108,951	3,598	3.4
2	Gen. Serv. Base Mo. Charge (92-GSBMC)	1,360,964	1,617,215	256,252	18.8
3	Irrigation (96-IR)	4,138,638	4,526,468	387,830	9.4
4	**Total**	5,604,954	6,252,634	647,680	

PART IV - REVENUE REQUIREMENTS

Q. Please summarize the concept of revenue requirements.

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

REVENUE REQUIREMENTS = OPERATING EXPENSE + MARGIN REQUIREMENT

To evaluate a cooperative's revenue requirement and the adequacy of its present rate structure to meet the requirement, it is common practice to analyze revenue and costs for a 12-month period of time called the Test Year.

Q. What Test Year was used to determine revenue requirements?

A. The Test Year revenue requirements for the study were based on Wheatland's actual historical operations for 12 months ending December 2007, with adjustments for known and measurable changes.

Q. Have you prepared a Statement of Operations for the Test Year based on the revenue generated by Wheatland's present rates?

A. Yes. Exhibit __(RJM-2) provides a Statement of Operations for the Test Year based on the revenue generated by Wheatland's present rates.

Page 1 of Exhibit __(RJM-2) provides a summary of the Statement of Operations for the Historical Test Year of January-December 2007. The results shown in Column (c) reflect an unadjusted Test Year as actually recorded on Wheatland's books. Column (d) summarizes the various normalizing adjustments to the revenue and expense accounts proposed by Wheatland with the resulting adjusted Pro Forma Test Year shown in Column (e).

Pages 2 and 3 of Exhibit __(RJM-2) provide a summary of each of the proposed adjustments. Pages 12 through 20 of Exhibit __(RJM-2) provide the detailed calculations for the following adjustments:

- Payroll;
- Payroll benefits;
- Depreciation;
- Property taxes;
- Long-Term Interest Expense;
- Rate Case Expense Amortization;

Pages 4 and 5 of Exhibit __(RJM-2) present the average number of consumers, energy sales, billing demand and revenue for Wheatland's rate classes as recorded for Historical and Pro Forma Test Years.

Pages 6 through 10 of Exhibit __(RJM-2) present the calculation of revenue under present rates for the Pro Forma Test Year. That is, these pages multiply Pro Forma Test Year number of consumers, energy sales and billing demand (page 5) times appropriate service schedule rates to determine the class and system revenue for the Pro Forma Test Year. These revenue calculations are based on Wheatland's present tariffed fixed and energy and demand rates for various rate schedules.

Q. What are Wheatland's Test Year revenue requirements?

A. Exhibit __(RJM-3) summarizes the operating results for Wheatland on both an unadjusted and an adjusted basis for the Test Year ended on December 31, 2007. A summary of the Operating Statement is provided as follows in Table 5.

Table 5 Statement of Operations - Present Rates		
Description	**12 Months Ending Dec. 31, 2007**	**Pro Forma Test Year**
	($)	($)
Operating Revenue	60,616,389	63,810,752
Operating Expenses[4]	57,520,067	63,560,795
Net Operating Income	3,096,322	249,957
Non-Operating Income		
Capital Credits	1,016,185	1,016,185
Other	1,192,548	1,192,548
Subtotal	2,208,733	2,208,733
Total Margins	5,305,055	2,458,690

It should be emphasized that the Net Operating Income stated is before interest expense on long term debt is deducted.

Column D of Exhibit __(RJM-3) shows that, in order to achieve the required TIER of 2.20, the present rates would need to support a total revenue requirement of $71,582,062.

Q. How was Wheatland's margin requirement calculated?

A. To complete the Test Year Revenue Requirement, an appropriate level of margin must be added to the previously determined operating expenses. The Wheatland Trustees have approved a TIER of 2.2 for purposes of calculating the margin requirements for this rate

[4] Before interest expense is deducted.

application. The TIER of 2.2 is, therefore, multiplied by the Test Year long-term interest expense of $4,650,000.

Q. Please identify the Operating Income required in the Test Year to achieve a 2.20 TIER.

A. To accomplish the 2.20 TIER, Wheatland needs to achieve an Operating Income (before Long-Term Interest) of $8,021,267.

Q. Has the TIER been endorsed by the MPUC?

A. Yes. KCC staff advises that the KCC regularly uses the TIER method in evaluating rate applications filed by electric cooperatives.

Q. Please summarize the increase Wheatland is requesting.

A. Wheatland's present rates, which have not changed since 1987 are generating insufficient operating margins of $249,957 in the Test Year. To achieve a TIER of 2.20, Wheatland's rates must generate $8,021,267 of operating margin. This difference of $7,771,310 is the amount of the shortfall and is therefore the increase required of Wheatland's retail rates. The following Table 6 presents the summary calculation.

Table 6
Revenue Requirements Summary
Method B - TIER = 2.20 Objective

		($)
1.	Operating Expenses (Excluding Interest)	63,560,795
2.	Margin Requirements	
	a. Interest expense	4,650,000
	b. Target TIER	2.20
	c. Total Margin Requirements (Before Interest)	10,230,000
	d. Less: Capital Credits	1,016,185
	e. Less: Non-Operating Income	1,192,548
	f. Net Operating Income Required	8,021,267
3.	Total Revenue Requirements	71,582,062
4.	Revenue From Present Rates	
	a. Tariff Revenue	63,364,571
	b. Other Operating Revenue	446,181
	c. Total Revenue	63,810,752
5.	Required Increase (Decrease)	7,771,310
	or	12.26%

PART V - COST OF SERVICE ANALYSIS

Q. Have you prepared a Cost of Service study for Wheatland?

A. Yes. A class COS analysis has been prepared to provide information to be used in evaluating and designing proposed rates. The basic objective of this analysis 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. We believe that this is generally the most appropriate technique to use in allocating cost responsibility to the various classes and developing rate design data.

Q. Does Wheatland have rates or consumers that are not necessarily handled in the best way possible in a fully allocated, average embedded COS analysis?

A. Yes. Wheatland serves some very large individual loads and wholesale accounts for which rates are based on things like negotiated contracts and/or special wholesale rates from Sunflower Electric Power Corporation ("Sunflower").

Q. Were these rates included in the class COS?

A. No. The result is that the COS allocates the increase to the rate classes from which the increase needs to be recovered.

Q. Please describe Exhibit __(RJM-4).

A. Exhibit __(RJM-4) includes the COS analysis for Wheatland. 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
12-14	Adjusted Statement of Operations
15-18	Summary of Classification Factors
19	Summary of Allocation of Revenue Requirements to Rate Classes
20	Allocation of Plant in Service to Rate Classes
21-23	Allocation of Revenue Requirements to Rate Classes
24	Rate Class Weighting Factors
25	Summary of Class Demands
26-28	Calculation of Class Demand Characteristics
27-30	Development of Allocation Factors.

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

A. It is vital at the outset to recognize some of the inherent limitations of such a study. First, it must be emphasized that a COS analysis, while basically an engineering 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; and 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 customers within each classification. The cost responsibility of a specific, individual consumer may or may not be entirely consistent with the cost allocations made to his/her assigned consumer classification. In particular, the study does not address the problem of maintaining relatively smooth transitions between the various rate classes or subclasses of customers which may be eligible to receive service under more than one rate schedule.

Third, accurate demand characteristics and load factor data for individual customer 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 customer acceptance or the avoidance of excessively abrupt changes from the historical rate policies of the cooperative. In addition, it does not recognize the need 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 customers.

With the above limitations in mind, a COS study should be used as a 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. 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. What do you mean by 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 the result of the number and location of each customer and which do not vary significantly with the demand imposed on the system or the amount of energy consumed. Metering and customer accounting expenses perhaps 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 operating

and maintaining a three-phase backbone feeder would generally fall within this category as would the demand charge from Wheatland's purchased power bills.

4. Energy - Costs which are related to the amount of energy used. The major item in this category is the energy charge in the purchased power rate. A portion of other general costs is customarily assigned to this category as well.

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

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

Q. Could you briefly 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-3). 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 general plant investment has minimal effect 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. Explain how revenue requirements were classified.

A. The Adjusted Operating Statement shown in Exhibit __(RJM-4), pages 12-14, 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-4). The factors used in the expense classification are summarized on pages 15 through 18 of Exhibit __(RJM-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, 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, 587, 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) - Administrative and General (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. Discuss the allocation of costs to rate classes.

A. The allocation of the revenue requirement to each consumer classification is presented on page 19 of Exhibit __(RJM-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 24 of Exhibit __(RJM-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 at least a token portion of the consumer related expense; hence, the 0.02 weighting factor.

3. Capacity Cost Allocations - Three different allocation factors were developed for the capacity component. (See pages 25 to 28 of Exhibit __(RJM-4) for the development of class demands):

   a. Line transformer capacity related costs were allocated in accordance with the estimated average monthly, 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 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 and distribution substation capacity costs were allocated in accordance with the average monthly coincidental class demands for the summer and non-summer seasons.

4. <u>Energy Cost Allocations</u> - 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 29 and 30 of Exhibit __(RJM-4).

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

A. Results obtained from the COS analysis are summarized in Tables 7, 8 and 9 on the following pages. Table 7 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 7
Cost of Service Summary

Rate Class	Revenue Present Rates[5]	Revenue Requirement	Increase (Decrease) Amount	Increase (Decrease) Percent[6]
	($)	($)	($)	
Residential (88-D)	9,786,357	10,903,975	1,117,618	11.6
Domestic Base Monthly (88-DBMC)	84,623	110,995	26,372	31.6
Non-Domestic Rural (NDR)	112,844	140,136	27,292	24.5
Municipal Power (88-M)	453,376	554,432	101,055	22.6
Gen. Serv. (88-GS)	12,174,047	14,838,458	2,664,411	22.2
Gen. Serv. Base Monthly (92-GSBMC)	1,076,756	1,501,587	424,831	40.0
Gen. Serv. TOD (96-GSTOD)	2,483,167	3,109,865	626,698	25.6
Gen. Serv. Large (88-GSL)	268,825	282,353	13,528	5.1
GS Lg. Base Monthly (92-GSLBMC)	517,230	668,677	151,446	29.7
Gen. Serv. Lg. TOD (96-GSLTOD)	3,853,312	4,692,016	838,705	22.1
Irrigation (96-IR)	3,324,866	4,980,541	1,655,675	50.4
Athletic Field Lighting (88-AF)	15,609	17,712	2,103	13.6
Street & Area Lighting (88-PSL)	175,122	231,523	56,401	32.6
(91-SL)	169,012	234,187	65,175	39.1
Total[7]	34,495,148	42,266,457	7,771,310	22.5

5 Includes an allocated share of Other Operating Revenue.

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

7 The class cost of service excludes rate classes or consumers which are served under contract rates or cost plus rates.

Table 8 shows a breakdown of the COS by cost category for each class.

Table 8
Cost Allocation Summary

Rate Class	Power Supply Capacity	Power Supply Energy	Trans-mission	Distribution Consumer	Distribution Capacity	Total COS
	($)	($)	($)	($)	($)	($)
Residential (88-D)	1,633,338	3,826,270	35,648	1,153,474	4,255,246	10,903,975
Domestic Base Monthly (88-DBMC)	18,208	39,776	382	8,336	44,293	110,995
Non-Domestic Rural (NDR)	16,380	30,789	315	54,313	38,339	140,136
Municipal Power (88-M)	81,719	203,907	1,829	45,422	221,555	554,432
Gen. Serv. (88-GS)	2,608,873	4,738,372	49,876	2,024,480	5,416,855	14,838,458
Gen. Serv. Base Monthly (92-GSBMC)	265,790	608,649	5,779	9,346	612,024	1,501,587
Gen. Serv. TOD (96-GSTOD)	497,086	1,262,825	11,515	117,560	1,220,879	3,109,865
Gen. Serv. Large (88-GSL)	46,914	117,366	1,099	1,739	115,234	282,353
GS Lg. Base Monthly (92-GSLBMC)	104,501	293,673	2,548	2,318	265,636	668,677
Gen. Serv. Lg. TOD (96-GSLTOD)	674,516	2,116,956	17,806	23,183	1,859,554	4,692,016
Irrigation (96-IR)	542,965	1,769,433	20,404	476,964	2,170,774	4,980,541
Athletic Field Lighting (88-AF)	512	2,391	23	12,436	2,351	17,712
Street & Area Lighting (88-PSL)	7,896	34,654	339	153,610	35,024	231,523
(91-SL)	14,571	65,156	633	88,533	65,294	234,187
Total	6,513,271	15,110,217	148,196	4,171,714	16,323,059	42,266,457

Table 9 provides total costs by class expressed in terms of $/customer/month (consumer component) and ¢/kWh (capacity and energy components).

Table 9
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 (88-D)	1.89	4.42	0.04	10.85	4.92	12.60
Domestic Base Monthly (88-DBMC)	2.02	4.42	0.04	10.85	4.92	12.34
Non-Domestic Rural (NDR)	2.35	4.42	0.05	10.98	5.51	20.13
Municipal Power (88-M)	1.77	4.42	0.04	33.80	4.80	12.02
Gen. Serv. (88-GS)	2.43	4.42	0.05	26.10	5.06	13.85
Gen. Serv. Base Monthly (92-GSBMC)	1.93	4.42	0.04	38.94	4.45	10.91
Gen. Serv. TOD (96-GSTOD)	1.74	4.42	0.04	40.82	4.28	10.89
Gen. Serv. Large (88-GSL)	1.77	4.42	0.04	48.30	4.34	10.64
GS Lg. Base Monthly (92-GSLBMC)	1.57	4.42	0.04	48.30	4.00	10.07
Gen. Serv. Lg. TOD (96-GSLTOD)	1.41	4.42	0.04	48.30	3.88	9.80
Irrigation (96-IR)	1.36	4.42	0.05	45.84	5.42	12.45
Athletic Field Lighting (88-AF)	0.95	4.42	0.04	19.06	4.35	32.76
Street & Area Lighting (88-PSL)	1.01	4.42	0.04	0.22	4.47	29.54
(91-SL)	0.99	4.42	0.04	0.22	4.43	15.89
Total	1.91	4.42	0.04	14.83	4.78	12.37

Q. Is any other cost analysis included in this filing besides the class COS study?

A. No.

PART VI - RATE DESIGN

Various tables showing the results of the COS analysis are useful in discussing the design and evaluation of Wheatland's rates. These tables, which have been previously presented, are listed below:

Table	Description
Table 7	Cost of Service Summary
Table 8	Cost Allocation Summary
Table 9	Unit Cost Summary

Q. What objectives have you considered while developing proposed rate changes?

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 Cooperative must be made.

Q. Please describe how the proposed rates were developed.

A. The first step in designing the proposed rates was to establish the 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 such as 1) the need to avoid abrupt changes and 2) the desire to achieve member-consumer acceptance also came into play. Thus, the dollar and percentage increase or decrease for each class as shown in Table 6 were tempered by experienced judgment in order to accomplish the overall rate design objectives.

Q. Please explain your rationale for deviating from the COS study in establishing the targeted class rate increases.

A. There are several reasons why I chose to deviate from a strict application of the COS analysis. First, in my opinion, it is generally undesirable to decrease any rate when requesting a general rate increase. On the other hand, increasing the rates charged a specific rate class by an amount which is substantially greater than the average overall rate increase is also undesirable as it may pose a hardship for the consumers in that class. 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 when possible.

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

A. Yes. Recognizing the principle of "rate moderation" and the principle of "member acceptance," 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 two-and-one-half times the average increase.
2. No class should receive a rate decrease.

One consequence of applying these guidelines is that a two-phase adjustment is being proposed to achieve the change needed in three rate classes. I will discuss this in more detail in later portions of my testimony.

Q. Summarize the revenue impact of your proposed rates.

A. The rate design recommendations contained and discussed herein result in a $7,790,598 revenue increase or 12.3 percent. This is being proposed to occur in two steps or phases. The majority of the increase (92 percent) will occur immediately upon KCC order and will affect the rate classes as shown in Table 10.

Table 10
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 (88-D)	9,659,775	10,818,004	1,158,229	12.0
2	Domestic Base Monthly Charge (88-DBMC)	83,529	105,353	21,824	26.1
3	Domestic Cooling & Heating (88-DCH)	149,071	175,015	25,944	17.4
4	General Service (88-GS)	12,016,580	14,892,278	2,875,698	23.9
5	General Service Cooling & Heating (88-GSCH)	29,428	33,999	4,570	15.5
6	General Service Large (88-GSL)	265,348	285,719	20,371	7.7
7	Municipal Power Service (88-M)	447,512	548,340	100,828	22.5
8	Non-Domestic Rural (88-NDR)	111,384	129,565	18,180	16.3
9	Private Street & Area Lighting (88-PSL)	172,857	218,907	46,049	26.6
10	Gen. Serv. Lg. Base Mo. Charge (92-GSBMC)	510,540	644,263	133,723	26.2
11	Lg. Industrial Interruptible (LG-IND)	495,661	495,661	-	0.0
12	Public Street Lighting (91-SL)	166,826	210,706	43,880	26.3
13	Athletic Field Lighting (88-AF)	15,408	18,284	2,877	18.7
14	Gen. Serv. Base Mo. Charge (92-GSBMC)	1,062,829	1,360,964	298,135	28.1
15	Gen. Serv. Lg. TOD (96-GSLTOD)	3,803,470	4,718,628	915,158	24.1
16	Gen. Serv. TOD (96-GSTOD)	2,451,048	3,071,722	620,674	25.3
17	Irrigation (96-IR)	3,281,860	4,138,638	856,777	26.1
18	Transmission Level Service (25 MW)	15,770,401	15,770,401	-	0.0
19	SP Contract (LAKIN)	888,218	888,218	-	0.0
20	Transmission Level Service (5MW)	11,982,825	11,982,825	-	0.0
21	Total	63,364,571	70,507,488	7,142,917	11.3

The second phase of the increase will only affect three rate classes and would take place 12 months after the effective date of Phase 1. The incremental impact of Phase 2 is shown in Table 11.

Table 11
Comparison of Revenue
Present and Proposed Rates (Phase 2)

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	**Rate Class**	**Revenue Present Rates**	**Revenue Proposed Rates**	**Increase (Decrease) Amount**	**Percent**
		($)	($)	($)	(%)
1	Domestic Base Monthly Charge (88-DBMC)	105,353	108,951	3,598	3.4
2	Gen. Serv. Base Mo. Charge (92-GSBMC)	1,360,964	1,617,215	256,252	18.8
3	Irrigation (96-IR)	4,138,638	4,526,468	387,830	9.4
4	**Total**	5,604,954	6,252,634	647,680	

Q. Why is it necessary to include a two-phase rate proposal?

A. For administrative, cost of service and public policy reasons, Wheatland is proposing to eliminate the Base Monthly Charge rates. Doing so and moving members directly to the applicable rate creates a very substantial increase -- greater than two-and-one-half times the average. Wheatland, therefore, is requesting this change be broken into two phases so that the impact is more gradual.

In addition, the increase required of the Irrigation rate exceeded the two-and-one-half guideline so a two-phase approach is also requested for that rate class.

Q. Please describe the proposed Power Cost Adjustment (PCA).

A. Around the country, including in Kansas, electric utilities use Power Cost Adjustments (PCA) in some form to automatically track changes in costs for power supply costs. Wheatland does not presently have a PCA; and so, when confronted with changes in its cost of purchasing power from Sunflower, it has had no way of adjusting what it collects from member-consumers except by changing its base rate via regulatory process.

Implementing a PCA will provide Wheatland with a mechanism to better track revenue with purchased power costs.

Q. What type of PCA is Wheatland proposing?

A. Because Wheatland owns no generating facilities and thereby purchases all of its power requirements from Sunflower, Wheatland proposes a PCA that captures changes in its total cost of purchased power. Again, Wheatland desires to avoid a situation whereby a wholesale rate change by Sunflower would require Wheatland to make its own retail rate filing.

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

A. Yes. Based on the purchased power expense for the Test Year, I have calculated a base cost per kWh sold of 62.2 mills or $0.0622. Per the PCA Schedule included in the proposed rate tariffs, Wheatland will charge or credit bills based on monthly variations from this base cost.

Q. Please describe the proposed rates.

A. Discussion of each of the proposed rates follows.

Residential (88-D)

The COS study shows the need to increase revenue from the Residential (88-D) class by $1,117,618 or a 11.6 percent increase (see Table 10) over revenue from present rates. Wheatland proposes to increase the Customer Charge from the present $3.80 to $6.00. The COS study shows that the consumer related costs for this class are $10.85 per consumer per month. While Wheatland's present Customer Charge is far below this amount and low compared to other cooperatives in the State, the proposed $6.00 Customer Charge is a significant step in the right direction. The present Energy Charge of $0.1057/kWh is proposed to increase to $0.11600/kWh. These proposed rates result in an increase to the Residential class of approximately 12.0 percent. For a range of increases over various consumption levels, please see Exhibit __(RJM-7), pages 1 and 2. A comparison of the present and proposed rates is shown as follows in Table 12.

Table 12
Comparison of Present and Proposed
Residential (88-D)

Description	Present Rate	Description	Proposed Rate
Customer Charge	$3.80/mo.	Customer Charge	$6.00/mo.
Minimum Bill-Town & Village	$6.00/mo.	Minimum Bill-Town & Village	$8.40/mo.
Energy Charge	$0.10570/kWh	Energy Charge	$0.11600/kWh

Domestic Base Monthly Charge (88-DBMC)

The COS study shows a required revenue increase from Domestic Base Monthly Charge (88-DBMC) consumers of $26,372 or 31.6 percent. Wheatland proposes to eliminate this rate and move the affected consumers to the proposed Residential (88-D) rate. It is further proposed that this occur in two phases. The first step will be to move the consumers to the rate structure that bills all current consumption at a uniform Energy Charge. This Energy Charge will be slightly lower than the proposed Energy Charge for the Residential rate so as to moderate the increase somewhat. This Phase 1 change is expected to produce an increase of 26.1 percent. A comparison of the present and proposed Phase 1 rates is shown as follows in Table 13.

Table 13 Comparison of Present and Proposed Phase 1 Domestic Base Monthly Charge (88-DBMC)			
Description	**Present Rate**	**Description**	**Proposed Rate**
Customer Charge	$3.80/mo.	Customer Charge	$6.00/mo.
Minimum Bill-Town & Village	$3.80/mo.	Minimum Bill-Town & Village	$8.50/mo.
Current Energy Charge	$0.10570/kWh	Energy Charge	$0.11200/kWh
Base Period Energy-Summer	$0.06670/kWh		
Base Period Energy-Winter	$0.05670/kWh		

In Phase 2, the rate will be equalized and consolidated with the Residential rate at the $0.116/kWh rate. This results in an additional 3.4 percent increase. A comparison of the present versus proposed Phase 2 rates is shown as follows in Table 14.

Table 14 Comparison of Present and Proposed Phase 2 Domestic Base Monthly Charge (88-DBMC)			
Description	**Present Rate**	**Description**	**Proposed Rate**
Customer Charge	$3.80/mo.	Customer Charge	$6.00/mo.
Minimum Bill-Town & Village	$3.80/mo.	Minimum Bill-Town & Village	$8.50/mo.
Current Energy Charge	$0.10570/kWh	Energy Charge	$0.11600/kWh
Base Period Energy-Summer	$0.06670/kWh		
Base Period Energy-Winter	$0.05670/kWh		

Domestic Cooling & Heating (88-DCH)

The Domestic Cooling & Heating (88-DCH) rate is intended to provide a reduced rate for consumers that have electric cooling and heating installed at their residence. The rates charged in the summer vary depending on whether or not the cooling load is controlled (cycled) during peak times. Wheatland proposes to maintain the present

$0.20 per month differential between the Customer Charge in this rate and the standard Residential rate. Wheatland also proposes to increase the non-controlled Summer Energy Charge per the Residential Energy charge. The controlled Summer Energy Charge and Winter Energy Charge will each be increased $0.0078/kWh to $0.067/kWh and $0.057/kWh, respectively. These proposed rates result in an increase of 17.4 percent for this class. A comparison of the present and proposed rates is shown as follows in Table 15.

Table 15
Comparison of Present and Proposed
Domestic Cooling & Heating (88-DCH)

Description	Present Rate	Description	Proposed Rate
Customer Charge	$4.00/mo.	Customer Charge	$6.20/mo.
Energy Charge		Energy Charge	
Summer (Jun-Sep)	$0.10570/kWh	Summer (Jun-Sep)	$0.11900/kWh
Summer LM (Jun-Sep)	$0.05920/kWh	Summer LM (Jun-Sep)	$0.06700/kWh
Winter (Oct-May)	$0.04920/kWh	Winter (Oct-May)	$0.05700/kWh

General Service (88-GS)

The COS study shows the need to increase revenues from the General Service (88-GS) class in the amount of $2,664,411 or 22.2 percent. Wheatland proposes to increase the Customer Charge from the present $6.00/month to $10.00/month. This is still below the COS results of $26.10/month; however, it is a substantial step in that direction. The present Demand Charge is also substantially below COS. Wheatland proposes to increase the Demand Charge from $6.00/kW to $9.45/kW to better recover power supply and distribution capacity costs. Finally, the current four-step, load-factor based Energy Charge structure is proposed to be simplified to a two-step structure. These proposed rates result in an increase of 22.5 percent for this class. For a range of increases over various consumption levels, please see Exhibit __(RJM-7), pages 3 and 4. A comparison of the present and proposed rates is shown as follows in Table 16.

Table 16
Comparison of Present and Proposed
General Service (88-GS)

Description	Present Rate	Description	Proposed Rate
Customer Charge	$6.00/mo.	Customer Charge	$10.00/mo.
Demand Charge	$6.00/kW	Demand Charge	$9.45/kW
Energy Charge		Energy Charge	
First 125 kWh/kW	$0.08670/kWh	First 375 kWh/kW	$0.08800/kWh
Next 125 kWh/kW	$0.07670/kWh	Over 375 kWh/kW	$0.05700/kWh
Next 125 kWh/kW	$0.06670/kWh		
Over 375 kWh/kW	$0.05420/kWh		

General Service Cooling & Heating (88-GSCH)

This rate is proposed to be the same as the Domestic Cooling & Heating (88-DCH) rate. These proposed rates result in an increase of about 15.5 percent for this class. A comparison of the present and proposed rates is shown as follows in Table 17.

Table 17
Comparison of Present and Proposed
General Service Cooling & Heating (88-GSCH)

Description	Present Rate	Description	Proposed Rate
Customer Charge	$4.00/mo.	Customer Charge	$6.20/mo.
Energy Charge		Energy Charge	
Summer (Jun-Sep)	$0.11060/kWh	Summer (Jun-Sep)	$0.11900/kWh
Summer LM (Jun-Sep)	$0.05920/kWh	Summer LM (Jun-Sep)	$0.06700/kWh
Winter (Oct-May)	$0.04920/kWh	Winter (Oct-May)	$0.05700/kWh

General Service Large (88-GSL)

The COS study shows the need to increase revenues from the General Service Large (88-GSL) class in the amount of $13,528 or 5.1 percent. Similar to the General Service proposal, Wheatland proposes to increase the Customer Charge and Demand Charge and reduce the number of blocks in the Energy Charge to better reflect COS results. Overall, the proposed rates result in a $20,371 increase. For a range of increases over various consumption levels, please see Exhibit __(RJM-7), pages 5 and 6. A comparison of the present and proposed rates is shown as follows in Table 18.

Table 18
Comparison of Present and Proposed
General Service Large (88-GSL)

Description	Present Rate	Description	Proposed Rate
Customer Charge	$6.00/mo.	Customer Charge	$10.00/mo.
Demand Charge	$12.00/kW	Demand Charge	$14.10/kW
Energy Charge		Energy Charge	
First 125 kWh/kW	$0.06170/kWh	First 375 kWh/kW	$0.05900/kWh
Next 125 kWh/kW	$0.05670/kWh	Over 375 kWh/kW	$0.04920/kWh
Next 125 kWh/kW	$0.05420/kWh		
Over 375 kWh/kW	$0.04920/kWh		

Municipal Power Service (88-M)

The COS study shows there is a need to increase the Municipal Power Service (88-M) rate by $101,055 or 22.6 percent. To achieve this, Wheatland proposes to increase the Customer Charge from $6.00/month to $10.00/month as in the General Service rate and to set the Energy Charge equal to the Residential Energy Charge. The proposed rates result in an increase of $100,828 or 22.5 percent. A comparison of the present and proposed rates is shown as follows in Table 19.

Table 19
Comparison of Present and Proposed
Municipal Power Service (88-M)

Description	Present Rate	Description	Proposed Rate
Customer Charge	$6.00/mo.	Customer Charge	$10.00/mo.
Energy Charge	$0.09530/kWh	Energy Charge	$0.11600/kWh

Non-Domestic Rural (88-NDR)

The COS shows that Wheatland could justify increasing the Non-Domestic Rural (88-NDR) rate by $27,292 or 24.5 percent. This rate has historically been tied to the

Residential rate, which Wheatland proposes to maintain. The result is an increase of $18,180 or 16.3 percent. The following Table 20 compares the present versus proposed rates.

Table 20
Comparison of Present and Proposed
Non-Domestic Rural (88-NDR)

Description	Present Rate	Description	Proposed Rate
Annual Customer Charge	$45.60/mo.	Annual Customer Charge	$72.00/mo.
Annual Minimum: ≤10 kVA	$144.00/year	Annual Minimum: ≤10 kVA	$204.00/year
Annual Minimum: >10 kVA	$12.00/kVA	Annual Minimum: >10 kVA	$17.00/kVA
Energy Charge	$0.10570/kWh	Energy Charge	$0.11600/kWh

Private Street & Area Lighting (88-PSL)

The COS shows the need to increase the Private Street & Area Lighting (88-PSL) rate by $56,401 or 32.5 percent. In particular, the COS suggests that the rates for metered lights are substantially under priced. The proposed rates result in an increase of $46,049 or 26.6 percent. The following Table 21 compares the present and proposed rates.

Table 21
Comparison of Present and Proposed
Private Street & Area Lighting (88-PSL)

Description	Present Rate	Description	Proposed Rate
Metered Lights		Metered Lights	
175 W MW	$2.18/mo.	175 W MV	$3.50/mo.
250 W MV	$2.45/mo.	250 W MV	$3.93/mo.
400 W MV	$3.27/mo.	400 W MV	$5.25/mo.
Unmetered Lights		Unmetered Lights	
175 W MW	$9.54/mo.	175 W MV	$10.50/mo.
250 W MV	$13.43/mo.	250 W MV	$13.50/mo.
400 W MV	$23.65/mo.	400 W MV	$23.65/mo.

General Service Large Base Monthly Charge (92-GSBMC)

The COS results show the need to increase the General Service Large Base Monthly Charge (92-GSBMC) by $151,446 or 29.7 percent. As is the case with all of Wheatland's Base Monthly Charge rates, this rate would be eliminated with consumers transferring to the standard General Service Large rate. The impact is an increase of $122,723 or 26.2 percent. A comparison of the present and proposed rates is shown as follows in Table 22.

Table 22
Comparison of Present and Proposed
General Service Large Base Monthly Charge (92-GSBMC)

Description	Present Rate	Description	Proposed Rate
		Customer Charge	$10.00/month
Current Demand Charge	$8.00/kW	Demand Charge	$14.10/kW
Energy Charge		Energy Charge	
First 125 kWh/kW	$0.06170/kWh	First 375 kWh/kW	$0.05900/kWh
Next 125 kWh/kW	$0.05670/kWh	Over 375 kWh/kW	$0.04920/kWh
Next 125 kWh/kW	$0.05420/kWh		
Over 375 kWh/kW	$0.04920/kWh		
Base Demand Charge	$8.00/kW		
Base Energy Charge	$0.04500/kWh		

Large Industrial Interruptible (LG-IND)

The Large Industrial Interruptible (LG-IND) rate is for a particular contract rate consumer. It contains an Energy Cost Adjustment (ECA) component that will adjust to collect increased ECA costs of Wheatland. As such, Wheatland is not proposing any base rate changes for this rate. The rate is as shown as follows in Table 23.

Table 23 Comparison of Present and Proposed Large Industrial Interruptible (LG-IND)			
Description	**Present Rate**	**Description**	**Proposed Rate**
Demand Charge	$12.00/kW	Demand Charge	$12.00/kW
Penalty Demand Charge	$20.00/kW	Penalty Demand Charge	$20.00/kW
Energy Charge	$0.04000/kWh	Energy Charge	$0.04000/kWh
Fuel Adjustment Clause	$0.02225/kWh	Fuel Adjustment Clause	$0.02225/kWh

Public Street Lighting (91-SL)

The COS results show the need for the Public Street Lighting (91-SL) class to be increased $65,175 or 39.1 percent. The proposed rates result in an increase of $43,880 or 26.3 percent. A comparison of the present and proposed rates is shown as follows in Table 24.

Table 24 Comparison of Present and Proposed Public Street Lighting (91-SL)			
Description	**Present Rate**	**Description**	**Proposed Rate**
Metered Lights	$0.11320/kWh	Metered Lights	$0.14300/kWh
Unmetered Lights		Unmetered Lights	
100 W HPS	$4.53/month	100 W HPS	$5.72/month
175 W MV	$7.36/month	175 W MV	$9.30/month
250 W MV/HPS	$10.98/month	250 W MV/HPS	$13.87/month
400 W MV/HPS	$20.38/month	400 W MV/HPS	$25.74/month

Athletic Field Lighting (88-AF)

The COS shows the need to increase the Athletic Field Lighting (88-AF) class by $2,103 or 13.6 percent. Wheatland proposes to increase the annual Customer Charge from $6.00/year to $8.00/year and to set the Energy Charge at the same rate as the Public Street Lighting Energy rate. The result is an increase of 18.7 percent. A comparison of the present and proposed rates is shown as follows in Table 25.

Table 25 Comparison of Present and Proposed Athletic Field Lighting (88-AF)			
Description	**Present Rate**	**Description**	**Proposed Rate**
Customer Charge	$6.00/year	Customer Charge	$8.00/year
Minimum Charge	$0.60/kVA	Minimum Charge	$0.65/kVA
Energy Charge	$0.10170/kWh	Energy Charge	$0.14500/kWh

General Service Base Monthly Charge (92-GSBMC)

The COS shows a need to increase the General Service Base Monthly Charge (92-GSBMC) by $424,831 or 40 percent. As is the case with all of Wheatland's Base Monthly Charge rates, this rate would be eliminated with consumers transferring to the standard General Service rate. Since doing so in one step would cause an increase exceeding two-and-one-half times the average, Wheatland proposes to achieve this objective in two phases. Phase 1 will include removing the Base Monthly Charges and increasing the end block Energy Charge. The increase resulting from this Phase is 28.1 percent. A comparison of the present and proposed Phase 1 rates is shown as follows in Table 26.

Table 26 Comparison of Present and Proposed Phase 1 General Service Base Monthly Charge (92-GSBMC)			
Description	**Present Rate**	**Description**	**Proposed Rate**
Customer Charge		Customer Charge	$10.00/mo.
Current Demand Charge	$6.00/kW	Demand Charge	$6.00/kW
Current Energy Charge		Energy Charge	
First 125 kWh/kW	$0.08670/kWh	First 125 kWh/kW	$0.08670/kWh
Next 125 kWh/kW	$0.07670/kWh	Next 125 kWh/kW	$0.07670/kWh
Next 125 kWh/kW	$0.06670/kWh	Next 125 kWh/kW	$0.06670/kWh
Over 375 kWh/kW	$0.05420/kWh	Over 375 kWh/kW	$0.05700/kWh
Base Demand Charge	$4.00/kW	Base Demand Charge	N.A./kW
Base Energy Charge	$0.05800/kWh	Base Energy Charge	N.A./kWh

To complete the transition, Phase 2 would include increasing the Demand Charge and flattening and increasing the Energy Charge applicable to the first 375 kWh/kW. The incremental increase for Phase 2 is 18.8 percent. A comparison of the present and proposed Phase 2 rates is shown as follows in Table 27.

Table 27
Comparison of Present and Proposed Phase 2
General Service Base Monthly Charge (92-GSBMC)

Description	Present Rate	Description	Proposed Rate
Customer Charge		Customer Charge	$10.00/mo.
Current Demand Charge	$6.00/kW	Demand Charge	$9.45/kW
Current Energy Charge		Energy Charge	
First 125 kWh/kW	$0.08670/kWh	First 375 kWh/kW	$0.08800/kWh
Next 125 kWh/kW	$0.07670/kWh	Over 375 kWh/kW	$0.05700/kWh
Next 125 kWh/kW	$0.06670/kWh		
Over 375 kWh/kW	$0.05420/kWh		
Base Demand Charge	$4.00/kW		
Base Energy Charge	$0.05800/kWh		

General Service Large TOD (96-GSLTOD)

The COS shows a need to increase the General Service Large TOD (96-GSLTOD) by $838,705 or 22.1 percent. In particular, the On-Peak Demand Charge is low compared to the COS. Wheatland proposes to increase the On-Peak Demand Charge and Energy Charge to achieve a 24.1 percent increase from this class. A comparison of the present and proposed rates is shown as follows in Table 28.

Table 28
Comparison of Present and Proposed
General Service Large TOD (96-GSLTOD)

Description	Present Rate	Description	Proposed Rate
Monthly kVA Charge		Monthly kVA Charge	
First 100 kVA	$200.00/mo.	First 100 kVA	$200.00/mo.
Excess kVA	$2.00/kVA	Excess kVA	$2.00/kVA
Facilities Charge	various/mo.	Facilities Charge	various/mo.
On-Peak Demand Charge	$8.00/kW	On-Peak Demand Charge	$12.10/kW
Energy Charge	$0.04500/kWh	Energy Charge	$0.05400/kWh

General Service TOD (96-GSTOD)

The COS shows a need to increase the General Service TOD (96-GSTOD) class by $626,698 or 25.6 percent. In particular, the On-Peak Demand Charge is low compared to the COS. Wheatland proposes to increase the On-Peak Demand Charge and Energy Charge to achieve a 25.3 percent increase from this class. A comparison of the present and proposed rates is shown as follows in Table 29.

Table 29
Comparison of Present and Proposed
General Service TOD (96-GSTOD)

Description	Present Rate	Description	Proposed Rate
Monthly kVA Charge		Monthly kVA Charge	
First 10 kVA	$20.00/mo.	First 10 kVA	$20.00/mo.
Excess kVA	$2.00/kVA	Excess kVA	$2.00/kVA
On-Peak Demand Charge	$4.00/kW	On-Peak Demand Charge	$7.80/kW
Energy Charge	$0.05800/kWh	Energy Charge	$0.06950/kWh

Irrigation (96-IR)

The COS shows a need to increase the Irrigation (96-IR) class by $1,655,675 or 50.4 percent. In particular, the Demand Charges are well below the COS results. Because of the magnitude of the needed increase, Wheatland proposes to implement an increase in two phases. Phase 1 will result in a 26.1 percent increase. A comparison of the present and proposed rates for Phase 1 is shown as follows in Table 30.

Table 30 Comparison of Present and Proposed Phase 1 Irrigation (96-IR)			
Description	**Present Rate**	**Description**	**Proposed Rate**
Customer Charge	$6.00/mo.	Customer Charge	$10.00/mo.
Minimum: ≤10 kVA	$12.00/year	Minimum: ≤10 kVA	$20.00/mo.
Minimum: >10 kVA	$1.00/kVA	Minimum: >10 kVA	$1.67/kVA
Demand Charge		Demand Charge	
Irrigation Months (Jul-Sep)	$6.00/kW	Irrigation Months (Jul-Sep)	$9.00/kW
Energy Charge		Energy Charge	
Irrigation Months (Jul-Sep)		Irrigation Months (Jul-Sep)	
First 125 kWh/kW	$0.08670/kWh	First 375 kWh/kW	$0.08800/kWh
Next 125 kWh/kW	$0.07670/kWh	Over 375 kWh/kW	$0.05700/kWh
Next 125 kWh/kW	$0.05420/kWh	Other Months	$0.07707/kWh
Over 375 kWh/kW	$0.05420/kWh		
Other Months	$0.05420/kWh		

Phase 2 will include another increase to the Summer Demand Charge in accordance with the COS results and will result in an incremental increase of 9.4 percent A comparison of the present and proposed rates for Phase 2 is shown as follows in Table 31.

Table 31 Comparison of Present and Proposed Phase 2 Irrigation (96-IR)			
Description	**Present Rate**	**Description**	**Proposed Rate**
Customer Charge	$6.00/mo.	Customer Charge	$10.00/mo.
Minimum: ≤10 kVA	$12.00/year	Minimum: ≤10 kVA	$20.00/mo.
Minimum: >10 kVA	$1.00/kVA	Minimum: >10 kVA	$1.67/kVA
Demand Charge		Demand Charge	
Irrigation Months (Jul-Sep)	$6.00/kW	Irrigation Months (Jul-Sep)	$16.50/kW
Energy Charge		Energy Charge	
Irrigation Months (Jul-Sep)		Irrigation Months (Jul-Sep)	
First 125 kWh/kW	$0.08670/kWh	First 375 kWh/kW	$0.08800/kWh
Next 125 kWh/kW	$0.07670/kWh	Over 375 kWh/kW	$0.05700/kWh
Next 125 kWh/kW	$0.05420/kWh	Other Months	$0.07707/kWh
Over 375 kWh/kW	$0.05420/kWh		
Other Months	$0.05420/kWh		

Transmission Level Service (5MW, 25MW)

The rates for Transmission Level Service (5MW, 25MW) are based on a pass through of wholesale power costs. As such, they will change as Sunflower changes the wholesale rates and/or ECA. These retail rate schedules were approved by the KCC on August 23, 2007 in Docket 07-WHLE-1117-TAR. Wheatland is not requesting any further changes to these tariffs at this time.

Q. Have you prepared various comparisons of the Present and Proposed Rates?

A. Yes, I have. Exhibits __(RJM-6) and __(RJM-7) provide several different comparisons of the present versus proposed rates as follows:

Exhibit __(RJM-6) - Comparison of Present and Proposed Rate Schedules
Exhibit __(RJM-7) - Comparison of Monthly Bills
Exhibit __(RJM-8) - Comparison of Phase 2 Proposed Rates

Q. Is Wheatland 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-9) includes Wheatland's present rate schedules. This exhibit is followed by Exhibit __(RJM-10) that includes redline versions of present rate schedules showing all proposed changes, additions and deletions. Finally, Exhibit __(RJM-11) presents a "clean" version of proposed rate schedules.

Q. Does this conclude your prefiled Direct Testimony?

A. Yes, it does.

STATE OF KANSAS

BEFORE THE KANSAS CORPORATION COMMISSION

Application for Revised Rates, Tariffs, and Rate Design Changes

of

Wheatland Electric Cooperative, Inc

Docket No. 09-WHLE-_________-RTS

February 27, 2009

EXHIBITS OF
RICHARD J. MACKE
LEADER, RATES AND FINANCIAL PLANNING
POWER SYSTEM ENGINEERING, INC.

ON BEHALF OF
WHEATLAND ELECTRIC COOPERATIVE, INC.

Exhibit	Title
Exhibit __(RJM-1)	Curriculum Vitae - Richard J. Macke
Exhibit __(RJM-2)	Statement of Operations - Present Rates
Exhibit __(RJM-3)	Revenue Requirements
Exhibit __(RJM-4)	Cost of Service Analysis
Exhibit __(RJM-5)	Statement of Operations - Proposed Rates
Exhibit __(RJM-6)	Comparison of Present and Proposed Rate Schedules
Exhibit __(RJM-7)	Comparison of Monthly Bills
Exhibit __(RJM-8)	Comparison of Phase 2 Proposed Rates
Exhibit __(RJM-9)	Present Rate Schedules
Exhibit __(RJM-10)	Present Rate Schedules with Redline Proposed Changes
Exhibit __(RJM-11)	Proposed Rate Schedules

Exhibit __(RJM-1)
Curriculum Vitae -
Richard J. Macke

SUMMARY OF EXPERIENCE & EXPERTISE

- Over 12 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 – Blaine, Minnesota (1999 – Present)

Leader, Rates and Financial Planning (April 2008 – Present)

Senior Rate and Financial Analyst (2002 – March 2008)
Senior Rate and Financial Analyst in Utility Planning and Rate Division. 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.

Rate and Financial Analyst (1999 – 2002)
Rate and Financial Analyst in Rates and Financial Planning Division. Emphasis on performing complex financial analyses, such as rate studies consisting of determination of revenue requirements, bundled and unbundled cost of service analysis and rate design. Other responsibilities include performing analysis of special rates and programs, key account analyses, financial forecasting, activity-based costing, policy development and evaluation and other financial analyses for various PSE clients.

Energy & Resource Consulting Group, LLC – Denver, Colorado (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, Louisiana 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 – Blaine, Minnesota (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. Provide analysis used to support testimony, mergers and acquisitions cases and financial forecasting.

Cenerprise, Inc. – Minneapolis, Minnesota (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.

EDUCATION

University of Minnesota – Minneapolis, Minnesota, 2007
Master of Business Administration
Emphasis: Finance and Strategic Management
Bethel University – St. Paul, Minnesota, 1996
Bachelor of Arts Degree in Business
Emphasis: Finance and Marketing
Minor: Economics

ADDENDUM REFERENCES

Expert Testimony

Exhibit __(RJM-2)
Statement of Operations -
Present Rates

Statement of Operations
Present Rates
For the Test Year Ended December 31, 2007

(a) Line No.	(b) Description	(c) Actual Test Year	(d) Adjustments [1]	(e) Pro Forma Test Year
1	**Operating Revenue**			
2	Sales of Electricity	$ 60,170,208	$ 3,194,363	$ 63,364,571
3	Other	446,181		446,181
4	**Total Operating Revenue**	$ 60,616,389	$ 3,194,363	$ 63,810,752
5				
6	**Operating Expenses**			
7	Cost of Purchased Power	41,871,287	6,036,603	47,907,890
8	Transmission - O & M	756		
9	Distribution - Operation	3,251,210	211,632	3,462,842
10	Distribution - Maintenance	2,048,166	127,224	2,175,390
11	Consumer Accounts	1,590,966	95,418	1,686,384
12	Consumer Service & Information	-	3,058	3,058
13	Sales	56,757		56,757
14	Administrative & General	2,986,896	184,321	3,171,217
15	Depreciation & Amortization	4,484,956	318,212	4,803,168
16	Taxes - Property	-		-
17	Taxes - Other	-		-
18	Interest on Long Term Debt	4,938,327	(288,327)	4,650,000
19	Other Interest Expense	934,984	(934,984)	-
20	Other Deductions	294,089		294,089
21	**Total Operating Expenses**	$ 62,458,394	$ 5,753,157	$ 68,210,795
22				
23	**Net Operating Margins**	$ (1,842,005)	$ (2,558,794)	$ (4,400,043)
24				
25	**Non-Operating Margins**			
26	Non-Operating Margins (Interest Income)	$ 1,229,889		$ 1,229,889
27	Income (Loss) from Equity Investments	(81,708)		(81,708)
28	Non-Operating Margins (Other)	44,367		44,367
29	Generation and Trasmission Capital Credits	-		-
30	Other Capital Credits & Patronage Dividends	1,016,185		1,016,185
31	Extraordinary Items	-		-
32	**Total Non-Operating Margins**	$ 2,208,733	$ -	$ 2,208,733
33				
34	**Total Patronage Capital & Margins**	$ 366,728	$ (2,558,794)	$ (2,191,310)

[1] See Page 2 and 3 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	$ 3,194,363
II. Purchased Power		
Schedule B - Purchased Power	11	$ 6,036,603
III. Distribution - Operations		
Schedule C - Payroll	14	$ 105,688
Schedule D - Payroll Related Expenses	17	$ 105,944
		$ 211,632
IV. Distribution - Maintenance		
Schedule C - Payroll	14	$ 63,535
Schedule D - Payroll Related Expenses	17	$ 63,689
		$ 127,224
V. Consumer Accounts		
Schedule C - Payroll	14	$ 47,651
Schedule D - Payroll Related Expenses	17	$ 47,767
		$ 95,418
VI. Consumer Service and Sales		
Schedule C - Payroll	14	$ 1,527
Schedule D - Payroll Related Expenses	17	$ 1,531
		$ 3,058

Supporting Adjustment Schedules
Summary of Adjustments

(a) Description	(b) Page	(c) Amounts
VII. Administrative and General		
Schedule C - Payroll	14	$ 87,055
Schedule D - Payroll Related Expenses	17	$ 87,266
Schedule G - Rate Case Expense	20	$ 10,000
		$ 184,321
VIII. Depreciation		
Schedule E - Depreciation	18	$ 318,212
IX. Interest on Long Term Debt		
Schedule F - Long Term Interest Expense	19	$ (288,327)

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

I. Consumer and Sales Data for December 31, 2007 (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 (88-D)	8,929	86,846,982	N.A.	9,729,140
2	Domestic Base Monthly Charge (88-DBMC)	64	904,194	N.A.	83,964
3	Domestic Cooling & Heating (88-DCH)	179	2,492,097	N.A.	141,724
4	General Service (88-GS)	6,456	103,254,048	473,256.0	11,681,837
5	General Service Cooling & Heating (88-GSCH)	12	452,626	N.A.	24,845
6	General Service Large (88-GSL)	4	3,538,880	11,778.0	352,288
7	Municipal Power Service (88-M)	109	4,487,693	N.A.	436,108
8	Non-Domestic Rural (88-NDR)	412	687,913	N.A.	110,034
9	Private Street & Area Lighting (88-PSL)	76	773,496	N.A.	174,687
10	General Service Large Base Monthly Charge (92-GSLBMC)	4	6,641,220	17,922.0	510,540
11	Large Industrial Interruptible (LG-IND)	1	4,946,052	15,647.0	492,554
12	Public Street Lighting (91-SL)	27	1,473,467	N.A.	168,436
13	Athletic Field Lighting (88-AF)	27	56,142	N.A.	16,000
14	General Service Base Monthly Charge (92-GSBMC)	20	13,764,169	47,381.0	1,063,057
15	General Service Large TOD (96-GSLTOD)	35	41,989,048	103,602.0	3,337,195
16	General Service TOD (96-GSTOD)	239	28,438,911	88,481.0	2,441,998
17	Irrigation (96-IR)	841	38,814,529	50,160.0	3,175,243
18	SP Contract (GC)	1	238,627,170	488,191.0	13,964,226
19	SP Contract (LAKIN)	1	16,100,864	34,944.0	884,213
20	SP Contract (ONEOK)	1	48,612,300	75,759.0	2,203,806
21	SP Contract (IBP)	1	139,157,360	233,539.0	8,717,052
22	SP Contract (CIG)	1	3,773,000	9,600.0	192,212
23	**Total** [2]	17,249	785,832,161	1,650,260.0	59,901,159
				Unbilled Revenu	269,941
				Adj. Total	60,171,100
				Check Total	60,170,208
				Difference	892

[1] Figures for calendar 2007 as reported by Wheatland and contained in Workpaper B.
[2] Total number of consumers excludes Domestic and General Service Cooling & Heating.

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 (88-D)	8,896	86,528,434	N.A.	9,659,775
2	Domestic Base Monthly Charge (88-DBMC)	64	899,509	N.A.	83,529
3	Domestic Cooling & Heating (88-DCH)	190	2,652,652	N.A.	149,071
4	General Service (88-GS)	6,465	107,154,996	480,089.9	12,016,580
5	General Service Cooling & Heating (88-GSCH)	15	569,739	N.A.	29,428
6	General Service Large (88-GSL)	3	2,654,160	8,833.5	265,348
7	Municipal Power Service (88-M)	112	4,611,207	N.A.	447,512
8	Non-Domestic Rural (88-NDR)	417	696,261	N.A.	111,384
9	Private Street & Area Lighting (88-PSL)	77	783,674	N.A.	172,857
10	General Service Large Base Monthly Charge (92-GSLBMC)	4	6,641,220	17,922.0	510,540
11	Large Industrial Interruptible (LG-IND)	1	4,946,052	15,647.0	495,661
12	Public Street Lighting (91-SL)	27	1,473,467	N.A.	166,826
13	Athletic Field Lighting (88-AF)	26	54,063	N.A.	15,408
14	General Service Base Monthly Charge (92-GSBMC)	20	13,764,169	47,381.0	1,062,829
15	General Service Large TOD (96-GSLTOD)	40	47,873,499	118,121.0	3,803,470
16	General Service TOD (96-GSTOD)	240	28,557,902	88,851.2	2,451,048
17	Irrigation (96-IR)	867	40,014,503	51,710.7	3,281,860
18	Transmission Level Service (25MW)	1	238,627,170	488,191.0	15,770,401
19	SP Contract (LAKIN)	1	16,100,864	34,944.0	888,218
20	Transmission Level Service (5MW)	2	187,769,660	309,298.0	11,982,825
1	**Total** [5]	17,263	792,373,201	1,660,989.4	63,364,571

Historical Revenue				60,170,208
Adjustment				3,194,363
Moved to Transmission Level Service (25MW)				
SP Contract (GC)	1	238,627,170	488,191	
Moved to Transmission Level Service (5MW)				
SP Contract (ONEOK)	1	48,612,300	75,759	
SP Contract (IBP)	1	139,157,360	233,539	
Transmission Service	2	187,769,660	309,298	
Moved to 88-GS				
SP Contract (CIG)	1	3,773,000	6,248	(metered)

1 Number of consumers as of December 2007.
2 Energy sales are based on historical average energy usage per consumer.
3 See Schedule A, pages 5 - 10.
4 Total number of consumers excludes Domestic and General Service Cooling & Heating.

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 (88-D)				
Customer Charge	8,896	cons.	$3.80	405,658
Minimum Bill-Town & Village	3,317	chrgs.	$6.00	19,903
Minimum Bill-Rural				60,428
Other Charges				27,731
Energy Charge	86,528,434	kWh	$0.10570	9,146,055
Energy Adjustment Charge	86,528,434	kWh		
				9,659,775
Domestic Base Monthly Charge (88-DBMC)				
Customer Charge				29,607
Base Period Energy - Summer	291,965	kWh	$0.06670	19,474
Base Period Energy - Winter	607,544	kWh	$0.05670	34,448
Energy Adjustment Charge	899,509	kWh		
				83,529
Domestic Cooling & Heating (88-DCH)				
Customer Charge	190	cons.	$4.00	9,120
Energy Charge		kWh		
Summer (Jun-Sep)	94,940	kWh	$0.10570	10,035
Summer LM (Jun-Sep)	407,654	kWh	$0.05920	24,133
Winter (Oct-May)	2,150,058	kWh	$0.04920	105,783
	2,652,652	kWh		149,071
General Service (88-GS)				
Customer Charge	5,037	chrgs.	$6.00	362,689
Minimum Bill-Town & Village		chrgs.		16,485
Minimum Bill-Rural		chrgs.		319,772
Other Charges				104,838
Demand Charge	480,090	kW	$6.00	2,880,540
Energy Charge				
First 125 kWh/kW	50,816,244	kWh	$0.08670	4,405,768
Next 125 kWh/kW	30,738,697	kWh	$0.07670	2,357,658
Next 125 kWh/kW	14,504,582	kWh	$0.06670	967,456
Over 375 kWh/kW	11,095,473	kWh	$0.05420	601,375
	107,154,996	kWh		12,016,580
General Service Cooling & Heating (88-GSCH)				
Customer Charge	15	cons.	$4.00	720
Energy Charge				
Summer (Jun-Sep)	13,148	kWh	$0.11060	1,454
Summer LM (Jun-Sep)	137,256	kWh	$0.05920	8,126
Winter (Oct-May)	388,795	kWh	$0.04920	19,129
	569,739	kWh		29,428

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
General Service Large (88-GSL)				
Customer Charge	3	cons.	$6.00	216
Minimum Bill				
Other Charges				4,511
Demand Charge	8,834	kW	$12.00	106,002
Energy Charge				
First 125 kWh/kW	1,104,188	kWh	$0.06170	68,128
Next 125 kWh/kW	1,054,260	kWh	$0.05670	59,777
Next 125 kWh/kW	465,165	kWh	$0.05420	25,212
Over 375 kWh/kW	30,548	kWh	$0.04920	1,503
	2,654,160	kWh		265,348
Municipal Power Service (88-M)				
Customer Charge	112	cons.	$6.00	8,064
Energy Charge	4,611,207	kWh	$0.09530	439,448
				447,512
Non-Domestic Rural (88-NDR)				
Annual Customer Charge	417	cons.	$45.60	19,015
Annual Minimums				18,774
Energy Charge	696,261	kWh	$0.10570	73,595
Energy Adjustment Charge		kWh		
				111,384
Private Street & Area Lighting (88-PSL)				
Metered Lights				
175 W MV	2,070	lights	$2.18	54,151
250 W MV	166	lights	$2.45	4,880
400 W MV	61	lights	$3.27	2,394
Unmetered Lights	783,674	kWh		
175 W MV	763	lights	$9.54	87,348
250 W MV	79	lights	$13.43	12,732
400 W MV	40	lights	$23.65	11,352
	3,179	lights		172,857
General Service Large Base Monthly Charge (92-GSLBMC)				
Base Monthly Charge				68,309
Base Demand Charge	17,922	kW	$8.00	143,376
Base Energy Charge	6,641,220	kWh	$0.04500	298,855
	6,641,220	kWh		510,540

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
Large Industrial Interruptible (LG-IND)				
Demand Charge	15,647	kW	$12.00	187,764
Penalty Demand Charge		kW	$20.00	
Energy Charge	4,946,052	kWh	$0.04000	197,842
Fuel Adjustment Clause [1]	4,946,052	kWh	$0.02225	110,055
				495,661
Public Street Lighting (91-SL)				
Metered Lights				
Energy Charge	417,551	kWh	$0.11320	47,267
Unmetered Lights	1,055,916	kWh		
100 W HPS	439	lights	$4.53	23,864
175 W MV	648	lights	$7.36	57,231
250 W MV/HPS	149	lights	$10.98	19,632
400 W MV/MH	77	lights	$20.38	18,831
	1,313	lights		166,826
Athletic Field Lighting (88-AF)				
Customer Charge	72	chrgs.	$6.00	433
Minimum Charge		chrgs.	$0.60	10,376
Energy Charge	45,216	kWh	$0.10170	4,598
Adjusted for kWh not billed due to minimum.				15,408
General Service Base Monthly Charge (92-GSBMC)				
Customer Charge	20	cons.		74,983
Base Demand Charge	47,381	kW	$4.00	189,524
Base Energy Charge	13,764,169	kWh	$0.05800	798,322
				1,062,829
General Service Large TOD (96-GSLTOD)				
Monthly kVA Charge				
First 100 kVA	40	cons.	$200.00	96,000
Excess kVA	304,097	kVA	$2.00	608,195
Facilities Charge				
On-Peak Demand Charge	118,121.0	kW	$8.00	944,968
Energy Charge	47,873,499	kWh	$0.04500	2,154,307
				3,803,470

[1] See page 11 for the Energy Cost Adjustment for the Test Year.

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
General Service TOD (96-GSTOD)				
Monthly kVA Charge				
First 10 kVA	240	cons.	$20.00	57,600
Excess kVA	190,843	kVA	$2.00	381,685
On-Peak Demand Charge	88,851	kW	$4.00	355,405
Energy Charge	28,557,902	kWh	$0.05800	1,656,358
				2,451,048
Irrigation (96-IR)				
Customer Charge	4,109	chrgs.	$6.00	24,655
Facilities Charge				113,641
Minimum: ≤ 10 kVA		chrgs.	$12.00	260,843
Minimum: > 10 kVA		chrgs.	$1.00	
Demand Charge				
Irrgation Months (Jul-Sep)	51,711	kW	$6.00	310,264
Other Months		kW		
Energy Charge				
Irrgation Months (Jul-Sep)	26,940,568	kWh		
First 125 kWh/kW	6,332,263	kWh	$0.08670	549,007
Next 125 kWh/kW	5,904,216	kWh	$0.07670	452,853
Next 125 kWh/kW	5,202,135	kWh	$0.06670	346,982
Over 375 kWh/kW	9,501,954	kWh	$0.05420	515,006
Other Months	13,073,934	kWh	$0.05420	708,607
	40,014,503	kWh		3,281,860
Transmission Level Service (25MW)				
Customer Charge	5	del. pts.	$105.00	6,300
Facility Charge	1	cons.	$13,563.08	162,757
Demand Charge				
Summer Demand	175,110	kW	$11.68	2,045,281
Non-Summer Demand	313,081	kW	$9.34	2,924,180
Transm. Srv. Demand	488,191	kW	$0.75	366,143
Energy Charge	238,627,170	kWh	$0.018520	4,419,338
Transm. Srv. Energy	238,627,170	kWh	$0.002500	596,568
WAPA Allocation	6,574,012	kWh	($0.009110)	(59,889)
ECA-02 [1]	238,627,170	kWh	$0.022251	5,309,724
	238,627,170	kWh		15,770,401

[1] See page 11 for the Energy Cost Adjustment for the Test Year.

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
SP Contract (Lakin)				
Schedule A (System Energy)				
Customer Charge	1	cons.	$105.00	1,260
Facility Charge	1	cons.	$4,761.00	57,132
Demand Charge	19,247	kW	$11.80	227,115
Energy Charge	6,355,997	kWh	$0.05182	329,368
				614,874
Schedule B (Firm Energy)				
Demand Charge	15,697	kW		-
Energy Charge	9,744,867	kWh	$0.01900	185,152
Energy Charge Adjustment	9,744,867	kWh	$0.00905	88,191
				273,344
				888,218
Transmission Level Service (5MW)				
Customer Charge	4	cons.	$105.00	5,040
Demand Charge				
Summer Demand	81,318	kW	$11.68	949,793
Non-Summer Demand	227,980	kW	$9.34	2,129,334
Transm. Srv. Demand	309,298	kW	$1.00	309,298
Energy Charge	187,769,660	kWh	$0.01852	3,477,465
Transm. Srv. Energy	187,769,660	kWh	$0.00500	938,848
ECA-02 [1]	187,769,660	kWh	$0.02225	4,178,087
				11,982,825

[1] See page 11 for the Energy Cost Adjustment for the Test Year.

Schedule B
Pro Forma Purchased Power Expense and Adjustment

Sunflower Electric Power Cooperative

	Units Purchased		Pro Forma Test Year Rate [1]	Amount
Schedule WHM-04				
Meter Charge	28	meters	$105.00 /mo.	$ 35,280
Demand Charges				
Summer Demand	465,351	kW-mo.	$11.68 /kW	$ 5,435,298
Non-Summer Demand	977,148	kW-mo.	$9.34 /kW	$ 9,126,561
				$ 14,561,859
Energy Charge [2]	799,289,759	kWh	$0.017913 /kWh	$ 14,317,677
Energy WAPA Credit	6,574,012	kWh	-$0.009110 /kWh	$ (59,889)
ECA-02	799,289,759	kWh	$0.022251 /kWh	$ 17,785,099
				$ 32,042,887
Property Tax Rider (est.)	799,289,759	kWh	$0.000607 /kWh	$ 485,043
Subtotal-WHM-04	799,289,759	kWh	$0.058959 /kWh	$ 47,125,069
Contract: City of Lakin				
Meter Charge	1	meters	$105.00 /mo.	$ 1,260
Demand Charge				
Summer Demand	16,000	kW-mo.	$0.00 /kW	$ -
Non-Summer Demand	19,250	kW-mo.	$11.80 /kW	$ 227,150
	35,250	kW-mo.		$ 227,150
Energy Charge				
Summer Energy	6,356,257	kWh	$0.051820 /kWh	$ 329,381
Non-Summer Energy	9,744,462	kWh	$0.028050 /kWh	$ 273,332
Energy 3-2-1 Credit	16,100,719	kWh	-$0.003000 /kWh	$ (48,302)
				$ 554,411
Subtotal-City of Lakin	16,100,719	kWh	$0.048620 /kWh	$ 782,821
Total	815,390,478	kWh	$0.058755 /kWh	$ 47,907,890

Pro Forma Purchased Power Expense	$ 47,907,890
Pro Forma Adjustment	$ 6,036,603
Historical Test Year Purchased Power Expense	$ 41,871,287

[1] Sunflower Electric Power Cooperative rates for 2009.
[2] Energy sales plus losses.

Schedule C
Adjustment to Payroll Expense

I. Adjustments to Union Payroll Expense			
A.	Actual wages recorded during the test year.		
1.	From January 1, 2007 to November 30, 2007 payroll		$ 2,865,977
2.	From December 1, 2007 to December 31, 2007 payroll		$ 270,965
			$ 3,136,942
B.	Adjustments to annualize December 1, 2007 payroll increase.		
1.	Test Year payroll prior to increase	$2,865,977	
2.	Percent increase	4.00%	
3.	Increase		$ 114,639
	Subtotal		$ 3,251,581
C.	Adjustments to annualize December 1, 2008 payroll increase.		
1.	Adjusted 2007 payroll	$3,251,581	
2.	Percent increase	3.00%	
3.	Increase		$ 97,547
D.	Total Pro Forma Test Year Payroll Increase - Union		
1.	Pro Forma Test Year Payroll - Union		$ 3,349,129
2.	Less: Test Year Payroll - Union		$ 2,865,977
3.	Total Payroll Increase - Union		$ 483,152
II. Adjustment to Non-Union Payroll Expense			
A.	Actual wages recorded during the test year.		
1.	From January 1, 2007 to November 30, 2007 payroll		$ 1,228,275
2.	From December 1, 2007 to December 31, 2007 payroll		$ 116,128
			$ 1,344,403
B.	Adjustments to annualize December 1, 2007 payroll increase.		
1.	Test Year payroll prior to increase	$1,228,275	
2.	Percent increase	3.00%	
3.	Increase		$ 36,848
	Subtotal		$ 1,381,251
C.	Adjustments to annualize December 1, 2008 payroll increase.		
1.	Adjusted 2007 payroll	$1,381,251	
2.	Percent increase	3.00%	
3.	Increase		$ 41,438
D.	Total Pro Forma Test Year Payroll Increase - Non-Union		
1.	Pro Forma Test Year Payroll - Non-Union		$ 1,422,689
2.	Less: Test Year Payroll - Non-Union		$ 1,228,275
3.	Total Payroll Increase - Non-Union		$ 194,414

Schedule C
Adjustment to Payroll Expense
(Continued)

III. Adjustment to Payroll Expense to Reflect Staffing Changes

A. New Employees Added During the Test Year

Union Employees	Actual Wages	Normalized Wages	Adjustment
Employee A	$ 28,388	$ 39,135	$ 10,747
Employee E	$ 34,440	$ 43,072	$ 8,632
Employee F	$ 17,507	$ 23,747	$ 6,240
Employee G	$ 9,815	$ 34,775	$ 24,960
Employee H	$ 8,593	$ 31,994	$ 23,401
Total	$ 98,743	$ 172,723	$ 73,980

Non-Union Employees	Actual Wages	Normalized Wages	Adjustment
Employee B	$ 14,786	$ 27,786	$ 13,000
Employee C	$ 13,556	$ 28,117	$ 14,561
Employee D	$ 40,950	$ 43,596	$ 2,646
Total	$ 69,292	$ 99,499	$ 30,207

B. Employees Leaving During the Test Year

		Union Employees	Actual Wages
Employee A	$ 31,790	$ 60,869	$ (60,869)
Employee B	$ 19,403	$ 38,976	$ (38,976)
Employee E	$ 93,852	$ 93,852	$ (93,852)
Employee F	$ 86,225	$ 86,225	$ (86,225)
		Total	$ (279,922)

		Non-Union Employees	Actual Wages
Employee C	$ 20,100	$ 24,260	$ (24,260)
Employee D	$ 29,784	$ 77,334	$ (77,334)
		Total	$ (101,594)

C. Employees Hired or Scheduled to be Hired During the Pro Forma Test Year

Non-Union Employees	Starting Date	Actual Wages	Source
Employee A	1/2/08	$ 27,000	
Total		$ 27,000	

Schedule C
Adjustment to Payroll Expense
(Continued)

IV. Summary

	Union	Non-Union	Total
1. Wages booked in Test Year	$ 3,136,942	$1,344,403	$ 4,481,345
2. Adjustments (Schedule C, Parts I, II, and III)			
Test Year Changes			
a. Increase in Wages	$ 483,152	$ 194,414	$ 677,565
b. New or Re-assigned Employees	$ 73,980	$ 30,207	$ 104,187
c. Retired or Re-assigned Employees	$ (279,922)	$ (101,594)	$ (381,516)
d. Pro Forma New Employee		$ 27,000	$ 27,000
Total Adjustments	$ 277,210	$ 150,027	$ 427,236
3. Total Pro Forma Test Year Payroll	$ 3,414,152	$1,494,430	$ 4,908,581

V. Allocation of Payroll Adjustment to Expense Categories

Category	Payroll Recorded in Test Year	Allocation Factor	Adjustment
Transmission	$ -	0.00%	$ -
Distribution Operations	$ 1,108,576	24.74%	$ 105,688
Distribution Maintenance	$ 666,428	14.87%	$ 63,535
Consumer Accounts	$ 499,821	11.15%	$ 47,651
Consumer Service	$ 16,020	0.36%	$ 1,527
Sales Expense	$ -	0.00%	$ -
Admin. and General	$ 913,134	20.38%	$ 87,055
Regulatory Expense	$ -	0.00%	$ -
Sub-total	$ 3,203,979	71.50%	$ 305,457
Other	$ 1,277,366	28.50%	$ 121,780
Total	$ 4,481,345	100.00%	$ 427,236

Schedule D
Adjustment to Payroll Related Expenses

	Union	Non-Union	Total
Total Change in Payroll per Schedule C	$ 277,210	$ 150,027	$ 427,236
A. Long Term Disability			
1. Adjustment due to increase in payroll			
a. Rate	0.00%	0.00%	0.00%
b. Adjustment	$ -	$ -	$ -
2. Adjustment due to increase in rate			
a. Total pro forma payroll	$ 3,414,152	$ 1,494,430	$ 4,908,581
b. Change in rate	0.00%	0.00%	0.00%
c. Adjustment	$ -	$ -	$ -
3. Subtotal Long Term Disability	$ -	$ -	$ -
B. FICA			
1. Adjustment due to increase in payroll			
a. Rate	7.65%	7.65%	7.65%
b. Adjustment	$ 21,207	$ 11,477	$ 32,684
2. Adjustment due to increase in rate			
a. Total pro forma payroll	$ 3,414,152	$ 1,494,430	$ 4,908,581
b. Change in rate	0.00%	0.00%	0.00%
c. Adjustment	$ -	$ -	$ -
3. Subtotal FICA	$ 21,207	$ 11,477	$ 32,684
C. Workmen's Compensation			
1. Adjustment due to increase in payroll			
a. Rate	4.68%	4.68%	4.68%
b. Adjustment	$ 12,973	$ 7,021	$ 19,995
2. Adjustment due to increase in rate			
a. Total pro forma payroll	$ 3,414,152	$ 1,494,430	$ 4,908,581
b. Change in rate	0.14%	0.14%	0.14%
c. Adjustment	$ 4,780	$ 2,092	$ 6,872
3. Subtotal Workmen's Compensation	$ 17,753	$ 9,113	$ 26,867

Schedule D
Adjustment to Payroll Related Expenses

	Union	Non-Union	Total
D. Hospitalization Expense			
1. Adjustment due to increase in payroll			
a. Rate	25.70%	25.70%	25.70%
b. Adjustment	$ 71,243	$ 38,557	$ 109,800
2. Adjustment due to increase in rate			
a. Total pro forma payroll	$ 3,414,152	$ 1,494,430	$ 4,908,581
b. Change in rate	-0.10%	-0.10%	-0.10%
c. Adjustment	$ (3,414)	$ (1,494)	$ (4,909)
3. Subtotal Hospitalization Expense	$ 67,829	$ 37,062	$ 104,891
E. Life Insurance			
1. Adjustment due to increase in payroll			
a. Rate	0.80%	0.80%	0.80%
b. Adjustment	$ 2,218	$ 1,200	$ 3,418
2. Adjustment due to increase in rate			
a. Total pro forma payroll	$ 3,414,152	$ 1,494,430	$ 4,908,581
b. Change in rate	-0.10%	-0.10%	-0.10%
c. Adjustment	$ (3,414)	$ (1,494)	$ (4,909)
3. Subtotal Life Insurance Expense	$ (1,196)	$ (294)	$ (1,491)
F. State and Federal Unemployment			
1. Adjustment due to increase in payroll			
a. Rate	0.00%	0.00%	0.00%
b. Adjustment	$ -	$ -	$ -
2. Adjustment due to increase in rate			
a. Total pro forma payroll	$ 277,210	$ 150,027	$ 427,236
b. Change in rate	0.00%	0.00%	0.00%
c. Adjustment	$ -	$ -	$ -
3. Subtotal Unemployment	$ -	$ -	$ -
G. Retirement and Pension			
1. Adjustment due to increase in payroll			
a. Rate	21.20%	21.20%	21.20%
b. Adjustment	$ 58,768	$ 31,806	$ 90,574
2. Adjustment due to increase in rate			
a. Total pro forma payroll	$ 3,414,152	$ 1,494,430	$ 4,908,581
b. Change in rate	3.46%	3.46%	3.46%
c. Adjustment	$ 118,130	$ 51,707	$ 169,837
3. Subtotal Retirement and Pension	$ 176,898	$ 83,513	$ 260,411

Schedule D
Adjustment to Payroll Related Expenses

	Union	Non-Union	Total
H. Accident Insurance			
1. Adjustment due to increase in payroll			
a. Rate	0.00%	0.00%	0.00%
b. Adjustment	$ -	$ -	$ -
I. Summary			
1. Long Term Disability	$ -	$ -	$ -
2. Workmen's Compensation	$ 17,753	$ 9,113	$ 26,867
3. Hospitalization Insurance Expense	$ 67,829	$ 37,062	$ 104,891
4. Life Insurance	$ 2,218	$ 1,200	$ 3,418
5. State and Federal Unemployment	$ -	$ -	$ -
6. Retirement and Pension	$ 176,898	$ 83,513	$ 260,411
7. Accident Insurance	$ -	$ -	$ -
8. Sub-Total	$ 264,698	$ 130,889	$ 395,587
9. FICA	$ 21,207	$ 11,477	$ 32,684
10. Total	$ 285,904	$ 142,366	$ 428,270

J. Allocation Payroll Related Expense Adjustments to Expense Categories

Category	Payroll Recorded in Test Year	Allocation Factor	Adjustment
Generation	$ -	0.00%	$ -
Transmission	-	0.00%	$ -
Distribution Operations	1,108,576	24.74%	$ 105,944
Distribution Maintenance	666,428	14.87%	$ 63,689
Consumer Accounts	499,821	11.15%	$ 47,767
Consumer Service	16,020	0.36%	$ 1,531
Sales Expense	-	0.00%	$ -
Admin. and General	913,134	20.38%	$ 87,266
Regulatory Expense	-	0.00%	$ -
Sub-total	$ 3,203,979	71.50%	$ 306,196
Other	1,277,366	28.50%	$ 122,074
Total	$ 4,481,345	100.00%	$ 428,270

Schedule E
Adjustment to Depreciation Expense

A. Depreciation on Existing Plant

1. Depreciation Expense Recorded on December 31, 2007	$380,764
2. Multiply by 12 Months	12
3. Normalized Depreciation Expense on Existing Plant	$4,569,168

B. Depreciation on New Plant to be Added During Pro Forma Test Year

Description of Plant	Amount	Depreciation Rate	Annual Depreciation Expense
Distribution Plant	$ 7,800,000	3.000%	$ 234,000
Transmission Plant	$ -	0.000%	$ -
General Plant	$ -	0.000%	$ -
Depreciation Expense - New Plant			$ 234,000

C. Summary

1. Total Depreciation Expense for the Pro Forma Test Year	$ 4,803,168
2. Less: Actual Depreciation Expense for the Test Year	$ 4,484,956
3. Adjustment to Depreciation Expense	$ 318,212

Schedule F
Adjustment to Long Term Interest Expense

A. Interest on Existing Loans

1.	Interest Expense for the Period Ending December 31, 2007	$ 4,938,327
2.	Less Interest Expense on non-electric debt.	638,327
3.	Adjusted Interest Expense on Existing Loans	$ 4,300,000

B. Interest on New Loans

1.	Estimated New Loans to be Requisitioned during 2008	$ 7,000,000
2.	Composite Interest Rate (See Section D., Below)	5.00%
3.	Estimated Interest Expense on New Loan Funds	$ 350,000

C. Summary

1.	Interest Expense for the Pro Forma Test Year	
	a. Interest on Existing Debt	$ 4,300,000
	b. Interest on New Debt	$ 350,000
	c. Total	$ 4,650,000
2.	Interest Expense for the Test Year	$ 4,938,327
3.	Adjustment to Interest on Long Term Debt	$ (288,327)

Schedule F
Adjustment to Long Term Interest Expense (Cont'd)

D. Calculation of Composite Interest Rate on New Loan Funds

	Amount	Percent of Loan Funds	Interest Rate	Weighted Interest Rate
RUS	$ -	0.0%		0.00%
CFC	7,000,000	100.0%	5.0%	5.00%
Total	$ 7,000,000	100.0%	5.0%	5.00%

Schedule G
Adjustment for Rate Case Expense

A. Adjustment for Rate Case Expense

1. Estimated Rate Case Expense	$ 30,000
2. Amortize Over 3 Years	3
3. Adjustment to A&G for Estimated Rate Case Expense	$ 10,000