BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS
DIRECT TESTIMONY OF

ROBERT D. BOWSER
VICE PRESIDENT REGULATORY AND TECHNICAL SERVICES

KANSAS ELECTRIC POWER COOPERATIVE, INC.

Docket No. 08-KEPE-597-RTS

Q. Please state your name and business address.

A. My name is Robert D. Bowser and my business address is Kansas Electric Power Cooperative, Inc., (KEPCo), 600 Corporate View, Topeka, Kansas 66615.

Q. By who are you employed?

A. I am employed by the Kansas Electric Power Cooperative, Inc., (KEPCo).

Q. What is your position with KEPCo?

A. I am the Vice President of Regulatory and Technical Services.

Q. Please state your educational background.

A. I graduated from Kansas State University in 1970 with a Bachelor of Science degree in Mathematics. In the spring of 1973, I received a Master of Science Degree in Statistics and in the fall of 1973, I received a PhD in Statistics, both from Kansas State University.

Q. Please state your professional experience.

A. From 1973 to 1979 I was an Assistant Professor of Mathematics at California State College, Bakersfield, California. I accepted the position of Systems Analyst with KEPCo in September 1979. As KEPCo's System Analyst, I worked for the Manager of Power Supply and Engineering and supported both the Engineering and Accounting staffs by programming computer solutions in their fields and by maintaining databases for their use, including programming and database maintenance for KEPCo's rates and rate cases. In July of 1984 I was promoted to Director, Revenue

Requirements and Computer Services. Over the years I have had several title changes. In my current position, I am responsible for regulatory activities at the Federal Energy Regulatory Commission (FERC) and the State Corporation Commission of Kansas (Commission or KCC) including overseeing KEPCo's participation in rate cases, KEPCo's Information Systems including its Energy Management System/System Control and Data Acquisition (EMS/SCADA) system, KEPCo's Dispatch Center, and overseeing the analytic work performed by departmental staff.

Q. Have you testified before the Commission in the past?

A. Yes, I have testified in several dockets before the Commission.

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

A. The purpose of my testimony is fourfold. First, I will sponsor Schedule 4 and Schedule 5 of Section 9 of KEPCo's filing, which deals with KEPCo's purchased power and transmission costs, and revenue. Second, I will sponsor KEPCo's method of weather normalization of both purchased power and revenue. I will then sponsor the Schedules in Section 17. Finally, I will provide support for KEPCo's request for a Demand Cost Adjustment (DCA) as part of its rate structure. Witness Carl Stover will support the actual DCA structure.

Q. Were the Schedules and Sections that you are sponsoring prepared by you or under your direct supervision?

A. Yes, these Schedules and Sections were prepared by me or under my direct supervision.

Adjustments to Purchased Power and Transmission Expense

Q. Would you please describe Schedule 4 of Section 9 of KEPCo's filing?

A. Schedule 4 of Section 9 supports KEPCo's *pro forma* adjustment #2 for purchased power and transmission consisting of billing correction *pro forma* adjustments to 2006 actual expense, weather normalization effects on KEPCo's purchased power and transmission expense, and additional *pro forma* adjustments due to changes that have occurred primarily due to changes in KEPCo's purchased power agreements. Page 1 of Schedule 4 includes KEPCo's purchased power and transmission suppliers, Column 1 shows the actual test year purchased power and transmission expense as recorded by KEPCo for each supplier, Column 2 shows the *pro forma* adjustments due to billing corrections to 2006, Column 3 shows the weather normalization adjustments, Column 4 shows the other *pro forma* adjustments, Column 5 shows the total of all *pro forma* and weather normalization adjustments, and Column 6 shows the adjusted weather normalized test year purchased power and transmission costs. Pages 2 through 8 of Schedule 4 detail the test year *pro forma* adjustments and weather normalization adjustments for KEPCo's purchased power and transmission suppliers.

Q. What *pro forma* adjustments to its purchased power and transmission costs due to billing corrections is KEPCo proposing?

A. KEPCo has several billing corrections, one that was made in 2006 for a billing error in 2005, several billing errors that were made in 2006 that were not corrected until 2007, and one correction to remove the effect of a credit not related to purchased power. In order to use 2006 as the test year, KEPCo believes that these adjustments must be made. Page 2 and 3 of Schedule 4 shows how these adjustments were calculated. In addition, KEPCo has made a $20 addition to costs of power in the KCP&L area to recognize an extra $20 credit that KEPCo received on its November billing from KCP&L.

Q. Exactly what billing corrections were made in 2006 for billing errors in 2005?

A. KEPCo has one billing correction that was made in 2006 for a 2005 bill. Westar Energy (Westar) bills KEPCo with an estimated bill on the fifth working day of each month so that KEPCo can record its expenses in the month they occur, even though not all of the information is available every month at that time. When an estimated billing occurs, KEPCo receives a correction towards the end of the month that appears on KEPCo's books in the next month. For the month of December 2005 that correction from Westar was a reduction of $26,829 in the December 2005 bill that KEPCo recorded in January 2006.

Q. You indicated that there were also billing errors made in 2006 that were not corrected until 2007. Will you explain those to the Commission?

A. Yes, I will. There are 6 adjustments to 2006 due to billing errors that were not corrected until 2007. Similar to the correction for December 2005 that KEPCo booked in January 2006, Westar had a correction to the December 2006 bill that was recorded in January 2007, resulting in a decrease of $34,668 to the December 2006 bill. In the same month, KEPCo also received an estimated bill recorded in December 2006 and a corrected bill from Sunflower Electric Power Corporation (Sunflower) that resulted in an increase of the December 2006 costs of $58,890 that was recorded by KEPCo in January 2007. The corrected billings for December 2005 and December 2006 are detailed on Page 2 of Schedule 4. Also on Page 2 of Schedule 4 is the reversal of the $2,719 credit for Westar's portion of Sharpe maintenance that was applied to KEPCo's purchased power billing from Westar in October 2006. The other four adjustments are for Southwest Power Pool (SPP) billings related to a transmission rate increase by Westar. In September and October of 2006, SPP billed the increase from the Westar transmission rate increase (FERC Docket ER05-925) of \$96,430, \$2,084, and \$13,371 that were refunded in 2007. The last adjustment is adding back in \$3,636 recognizing the rate increase from Westar. The calculations of these pro forma adjustments are listed on Page 3 of Schedule 4.

Q. Column 3 on Page 1 of Schedule 4 is for weather normalization. Did KEPCo use a commonly accepted method of weather normalization?

A. Yes, KEPCo did use a methodology that has previously been accepted by the Commission. I will discuss the methodology later in my testimony. Page 4 of Schedule 4 shows the changes in billing units, average rates, and total dollars adjusted for each of KEPCo's purchased power suppliers due to weather normalization.

Q. According to your testimony, Column 4 on Page 1 of Schedule 4 shows other *pro forma* adjustments. Would you please describe the adjustments found in that column?

A. A number of adjustments to the test year are necessary to recognize some events that happened during the test year and some events that have happened since the test year. The first adjustment is elimination of the charges that KEPCo was paying to Empire District Electric (EDE) under a transmission contract that expires May 31, 2008. KEPCo now takes transmission under the SPP Open Access Transmission Tariff (SPP OATT) for service to its delivery points in the EDE area and those costs are included in the SPP charges for 2006. That adjustment is calculated on Page 5 of Schedule 4. The second adjustment recognizes KEPCo's new contract with Kansas City Power & Light (KCP&L) and the units, rates, and total dollars associated with both the old contract and the new contract are shown on Page 6 of Schedule 4. The third adjustment is a reduction in purchased power from the Southwest Power Administration (SWPA) to eliminate the effect of special power purchases that were necessary in 2006 due to drought conditions in the SWPA area. SWPA power is generated at several dams in Missouri and Arkansas that experienced severe drought conditions in late 2005 and 2006. We do not expect those conditions to return to the area soon. The adjustment is to purchase the same amount of scheduled energy at the regular contract rate. Page 7 of Schedule 4 details that adjustment. The fourth adjustment is being made to annualize the effect of a new contract between KEPCo and Sunflower that went into effect on June 1, 2006. The rates, units, and corresponding dollars from the first five months of the year plus individual corrections for June and July for both the old contract and new contract are shown on Page 8 of Schedule 4.

Adjustments to Member Revenue

Q. Would you please describe Schedule 5 of Section 9 of KEPCo's filing?

A. Yes, Schedule 5 of Section 9 contains the *pro forma* and weather normalization adjustments for Member Revenue in the 2006 Test Year. It consists of one page with six (6) columns like Page 1 of Schedule 4. Column 1 shows KEPCo's revenue according to its books and records. Column 2 shows adjustments to the billings to KEPCo's Members for the Test Year. Column 3 shows the weather normalization adjustments. Column 4 shows the adjustments that come as a result of the *pro forma* adjustments to Purchased Power and Transmission made due to changes in power agreements. The total of the *pro forma* adjustments are shown in Column 5 and the final adjusted revenue is shown in Column 6.

Q. Column 2 shows an adjustment of $35,828 to the Member Revenue. Why is that adjustment required?

A. In 2006, KEPCo made billing corrections for two Members that included years prior to 2006 reducing 2006 revenue by $35,828. This adjustment recognizes those corrections.

Q. Please explain the other adjustment proposed in Schedule 5.

A. The weather normalization adjustment is a result of applying KEPCo's present rate to the weather normalized demand and energy for each KEPCo Member in the Test Year and comparing that to the actual revenue collected for each Member.

Weather Normalization

Q. You are testifying on KEPCo's weather normalization. How did KEPCo do its weather normalization?

A. KEPCo started with a linear regression model where usage is dependent on both cooling degree days and heating degree days. The precise model that KEPCo started with was:

$$\boldsymbol{Y = \alpha + \beta^* X_{cdd} + \gamma^* X_{hdd} + \varepsilon}$$

where $\boldsymbol{Y}$ is usage, $\boldsymbol{X_{cdd}}$ is cooling degree days, $\boldsymbol{X_{hdd}}$ is heating degree days, α represents a base usage with zero cooling degree days and zero heating degree days, β is the coefficient for cooling degree days, γ is the coefficient for heating degree days, and ε represents the error term in the regression. KEPCo supplies power to 19 Members in six different control areas. There are 37 different Member/control area combinations with different weather stations. Since each of the 37 different areas belong to different Members and/or control areas, KEPCo's analysis looked at each of the 37 areas separately. Also, since KEPCo's billing to its Members and the supplier billings to KEPCo use both demand (kW) units and energy (kWh) units, KEPCo needed to weather normalize both demand and energy.

Q. How did KEPCo normalize the energy component?

A. Each of the 37 areas previously described was paired with a weather station in close proximity. Raw usage, cooling degree days, and heating degree days for each area for each of the 60 months ending with December 2006 were collected. KEPCo used the statistical computer program E-

Views Version 6.0 to run a regression on adjusted usage for each area. The regression coefficients, R^2 (a measure of fit), and the Durbin-Watson statistic for each regression are given on the first page of Exhibit RDB-1. A significant number of the regressions show a degree of autocorrelation as determined by the Durbin-Watson statistic, which undermines the results of the regression.

Q. How did you correct for the autocorrelation found in your analysis?

A. Two sources of problems in the regression were discovered. The first resulted from using the raw usage data at KEPCo Member delivery points. The raw usage data included the loads of large commercial accounts that, in general, are not as sensitive to weather as residential customers. To correct for commercial accounts, the usage of each affected area was reduced by the sales to the commercial accounts. This affected nine of the 37 areas. Only some of KEPCo's Members' largest commercial accounts were accounted for in this way.

Q. Did this eliminate all of the autocorrelation that was originally observed?

A. No. The regressions were rerun for the nine affected areas and the results (regression coefficients, R^2, and Durbin-Watson statistics) following the commercial correction can be found at the bottom of Page 1 of Exhibit RDB-1. Several regressions still showed some autocorrelation.

Q. What did KEPCo do next to reduce the autocorrelation?

A. To correct for the autocorrelation, KEPCo used the first-order autocorrelation correction in E-Views. The resulting regression coefficients, R^2, and the Durbin-Watson statistic for these regressions are given on Page 2 of Exhibit RDB-1.

Q. How did KEPCo use these results to determine weather normalized energy sales and purchases?

A. KEPCo applied the resulting regression coefficients to the difference between "normal" Heating and Cooling Degree Days and the actual Heating and Cooling Degree Days for each month in the test year and for each of the 37 areas:

$$\textbf{Adjustment} = \beta*(X_{cdd\text{-}Norm} - X_{cdd\text{-}Act}) + \gamma*(X_{hdd\text{-}Norm} - X_{hdd\text{-}Act})$$

where β and γ are the regression coefficients, $X_{cdd\text{-}Norm}$ is the "normal" cooling degree days, $X_{cdd\text{-}Act}$ is the actual cooling degree days, $X_{hdd\text{-}Norm}$ is the "normal" heating degree days, and $X_{hdd\text{-}Act}$ is the actual heating degree days. These adjustments were then added to the actual energy sales for each month. Finally, the results were combined back to KEPCo's 19 Members for energy sales and 7 control areas for energy purchases.

Q. How did KEPCo weather normalize for demand (kW)?

A. Prior to KEPCo's 1998 filing in Docket No. 99-KEPE-025-RTS my staff and I had several discussions with the KCC staff. Those discussions led KEPCo to settle on making an assumption about load factors. KEPCo assumed that the monthly load factors for each area would remain the same under weather normalization. KEPCo then used the weather normalized energy for each area and load factors to determine appropriate corresponding demands.

Q. How did you then use the weather normalized demand and energy?

A. I applied my power cost model to the weather normalized demand and energy for each control area to determine billing units to which I then applied the appropriate rates. The effects of weather normalization for purchased power are shown on Page 3 of Schedule 4, as previously mentioned. Similarly, I applied a sales model to KEPCo's Members' weather normalized units to develop billing units and adjusted revenue. Those results are shown in Section 17.

Test Year Revenues – Proposed Tariff

Q. You mentioned earlier that you are sponsoring Section 17, is that correct?

A. Yes, Section 17 was prepared under my direction and I am sponsoring it.

Q. Please describe Schedule 1 of Section 17.

A. Schedule 1 consists of a table with 10 columns. Column 1 lists each of KEPCo's Members. The weather normalized Test Year kWh for each Member is listed in Column 2. Column 3 gives the weather normalized revenue under KEPCo's existing M-9 tariff from each Member including all *pro forma* adjustments, while Column 4 gives the corresponding average annual rate for each Member. Columns 5 and 6 give the revenue and average annual rate under KEPCo's proposed M-10 tariff. The dollar difference between the tariffs is shown in Column 7, the difference in average annual rates in Column 8, the percent increase for each Member in Column 9, and the difference in percent for each Member from the average annual increase for all Members in Column 10.

Q. Will you please describe Schedule 2 of Section 17?

A. Schedule 2 consists of 19 pages, one for each Member, that detail the effects of applying M-10 to the weather normalized billing units for the Test Year.

Power Cost Adjustment

Q. Does KEPCo presently use a Power Cost Adjustment (PCA) in its tariff to its Members?

A. Yes, it does. In KEPCo's last rate case, 01-KEPE-1106-RTS, the Commission approved an Energy Cost Adjustment (ECA), which is one form of a PCA, that captures the variations in the cost of purchased energy and fuel to KEPCo.

Q. Does KEPCo wish to make any changes to its Power Cost Adjustment in this filing?

A. Yes, it does. Since its last filing, KEPCo has begun to experience variation in its cost of capacity or demand from its power suppliers. One of its primary power suppliers, Westar, is proposing a formula based demand rate for a new contract for power with KEPCo. To recognize the volatility in demand costs that are not controlled by KEPCo, KEPCo proposes to add a Demand Cost Adjustment (DCA) to KEPCo's tariff.

Q. Is it common to include demand costs in a PCA?

A. In its Order in Docket No. 106,850-U, the Commission's 1977 ruling on PCAs, the total cost of purchased power, including demand costs, was included in the calculation in Appendix B. Appendix B was for "Rate schedules of all cooperative and municipals which purchase substantially all power ..." including KEPCo and its Members. KEPCo's first tariff included demand costs in its PCA. Both KEPCo and the Commission recognized that the PCA referenced in Appendix B, putting both demand and energy costs in a single adjustment and applying it to energy sales, worked well for cooperatives that billed end users on their energy use, a generation and transmission cooperative like KEPCo that bills its Members on both demand and energy use should have a separate DCA and ECA.

Q. What is KEPCo's history with a PCA?

A. As previously mentioned, KEPCo's first tariff, which was approved in Docket No. 135,368-U in 1983 during a time when both demand and energy prices were extremely volatile, included a PCA consisting of a DCA and an ECA that were calculated monthly based on KEPCo's actual cost of demand and energy in the billing month. KEPCo continued to include both a DCA and an ECA in its tariffs until the early 1990s during a time when energy prices had finally stabilized. Not having a PCA served KEPCo well for about ten years. In 2001, when KEPCo filed for its present tariff in Docket No. 01-KEPE-1106-RTS, due to increased volatility in its cost of energy from its suppliers, KEPCo requested that an ECA type of PCA be included in its tariff, which the Commission approved. Now that KEPCo is experiencing volatility in its demand costs as well, it is making a similar request to include a DCA in its PCA.

Q. Does KEPCo propose a DCA like it had in the past?

A. No, it does not. KEPCo's Members are concerned about having a DCA that adjusts monthly. They want to know what their demand rate is going to be for several months at a time. Therefore, KEPCo is requesting a DCA that adjusts once each year, in January, including a correction factor that would ensure that KEPCo only collects the variation in the actual cost of the demand component of its purchased power through its DCA. KEPCo expects the demand component of its purchased power to rise over the next several years and with only one adjustment each year, expects its collection of additional demand costs to lag the actual cost increases.

Q. Does KEPCo have any additional concerns about its purchased power costs?

A. Yes, it does. KEPCo and Westar have negotiated a new contract that has been filed at the FERC in Docket No. ER07-1344. The filing has been set for settlement negotiations and a hearing if necessary and KEPCo does not know when the contract will receive the approval of the FERC and be allowed to go into effect. The new contract is heavily weighted toward the demand component of power cost compared to KEPCo's present contract with Westar, with a corresponding decrease in the energy component. The decrease in the energy component will flow back to KEPCo's Members through KEPCo's monthly ECA. When that contract goes into effect, KEPCo will need to make a one time adjustment to its DCA to account for that demand cost increase. Since KEPCo is including an annual correction factor in its DCA, any under or over collection resulting from this one time adjustment to the DCA will be captured in the next annual adjustment to the DCA.

Q. Does this complete your testimony?

A. Yes, it does.

Regression Results

Time Period: Monthly Data from Jan/2002 through Dec/2006

			Regression Parameters				*Durbin-Watson Autocorrelation*			
COOP	***Area***	***Weather Station***	***Intercept***	***Beta_CDD***	***Beta_HDD***	***r-sqr.***	***Value***	***@ .05 Sig.***	***@ .01 Sig.***	***Use***
AV	KGE	Hutchinson	168,660	467	57	0.891	0.956	Yes	Yes	
AV	KPL	Hutchinson	1,474,317	3,824	766	0.915	1.086	Yes	Yes	
AV	MWE	Hutchinson	2,274,107	4,093	704	0.884	1.546	Inc.	No	Y
AV	WPE	Hutchinson	1,267,124	1,831	(43)	0.796	1.071	Yes	Yes	
BA	KPL	Leavenworth	4,896,156	5,177	871	0.352	0.205	Yes	Yes	
BL	KPL	Concordia	3,630,023	9,227	2,478	0.922	1.185	Yes	Yes	
BL	STM	Concordia	8,485	9	(1)	0.407	0.187	Yes	Yes	
BL	WPE	Concordia	1,370,632	1,741	761	0.592	0.955	Yes	Yes	
BU	KGE	Winfield	5,754,856	13,467	3,946	0.933	1.244	Yes	Yes	
BU	KPL	Winfield	150,010	187	71	0.793	1.135	Yes	Yes	
CM	SUN	Dodge	1,388,641	1,937	60	0.874	2.167	No	No	Y
CM	WPE	Dodge	6,392,105	5,159	465	0.681	0.732	Yes	Yes	
CV	KGE	Winfield	3,235,372	6,290	1,368	0.910	0.893	Yes	Yes	
DS	KPL	Abilene	6,042,082	12,783	4,688	0.852	0.520	Yes	Yes	
DS	WPE	Abilene	91,866	135	89	0.902	1.504	Yes	No	
FH	KPL	Cottonwood Falls	4,253,222	9,150	2,254	0.946	1.491	Yes	No	Y
HL	EDE	Independence	849,997	2,425	804	0.911	0.440	Yes	Yes	
HL	KCP	Independence	1,807,693	4,338	1,803	0.879	0.811	Yes	Yes	
HL	KGE	Independence	4,637,958	10,514	3,285	0.894	0.719	Yes	Yes	
LC	KCP	Cottonwood Falls	849,287	2,035	632	0.868	1.076	Yes	Yes	
LC	KGE	Cottonwood Falls	1,629,903	2,568	748	0.847	1.054	Yes	Yes	
LC	KPL	Cottonwood Falls	3,090,813	5,797	1,618	0.918	1.477	Yes	Inc.	Y
LJ	KPL	Leavenworth	6,000,190	13,933	3,986	0.848	0.481	Yes	Yes	
NI	MWE	Pratt	732,001	4,175	340	0.928	2.185	No	No	Y
NI	WPE	Pratt	3,036,730	6,909	220	0.822	1.435	Yes	Inc.	
PL	WPE	Norton	1,673,230	1,493	377	0.660	0.664	Yes	Yes	
RA	KGE	Independence	3,419,917	5,500	1,591	0.456	0.109	Yes	Yes	
RH	KPL	Concordia	224,494	574	127	0.956	1.526	Inc.	No	Y
RH	MWE	Concordia	282,931	181	31	0.611	1.234	Yes	Yes	
RH	WPE	Concordia	6,411,542	15,576	3,425	0.930	2.406	No	No	Y
SC	KGE	Winfield	3,720,586	7,320	1,830	0.901	0.866	Yes	Yes	
SC	WPE	Winfield	423,376	1,106	182	0.754	0.879	Yes	Yes	
SG	KGE	Hutchinson	6,023,325	14,588	2,515	0.827	0.371	Yes	Yes	
TV	EDE	Independence	74,371	235	73	0.885	0.840	Yes	Yes	
TV	KGE	Independence	601,318	1,393	406	0.855	0.508	Yes	Yes	
TV	KPL	Independence	1,028,793	2,727	686	0.785	0.208	Yes	Yes	
VI	WPE	Dodge	8,602,243	10,528	702	0.648	1.432	Yes	Inc.	
AV	WPE2	Hutchinson	420,217	1,277	140	0.894	1.765	No	No	Y
BA	KPL2	Leavenworth	3,139,885	4,425	1,257	0.897	1.558	Inc.	No	Y
BL	WPE2	Concordia	910,092	2,128	481	0.910	1.513	Inc.	No	Y
CM	WPE2	Dodge	5,322,074	5,631	313	0.797	0.783	Yes	Yes	Y
DS	KPL2	Abilene	5,895,175	13,009	4,669	0.861	0.534	Yes	Yes	Y
NI	WPE2	Pratt	2,036,637	7,040	580	0.918	2.212	No	No	Y
RA	KGE2	Independence	3,327,006	5,456	1,621	0.569	0.164	Yes	Yes	Y
VI	WPE2	Dodge	4,262,377	8,965	527	0.895	1.462	Yes	Inc.	Y

Notes: Some Large customers were subtracted from the base group to define 8 areas:
AV WPE2 - The Pretty Prairie delivery point is subtracted from AV WPE
BA KPL2 - City of Seneca subtracted from BA KPL
CM WPE2 - The city of Meade customer is subtracted from CM WPE
BL WPE2 - The Linn and Enron delivery points are subtracted from BL WPE
NI WPE2 - The large Northern Natural customer is subtracted from NI WPE
RA KGE2 - The NW Frederick delivery point was subtracted from RA KGE
SG KGE2 - The Koch delivery point is subtracted from SG KGE
VI WPE2 - The Koch & Praxair delivery points are subtracted from VI WPE
The Bluestem St.Marys customer is the only customer in the area BL STM

Regression Results

Time Period: Monthly Data from Jan/2002 through Dec/2006

			Regression Parameters					Durbin-Watson Autocorrelation			
COOP	*Area*	*Weather Station*	*Intercept*	*Beta_CDD*	*Beta_HDD*	*AR-1*	*r-sqr.*	*Value*	*@ .05 Sig.*	*@ .01 Sig.*	*Use*
AV	KGE	Hutchinson	166,428	469	66	0.5340	0.913	2.131	No	No	Y
AV	KPL	Hutchinson	1,477,895	3,763	804	0.4625	0.934	2.286	No	No	Y
AV	MWE	Hutchinson	2,278,178	4,063	704	0.2036	0.889	1.921	No	No	Y
BL	KPL	Concordia	3,597,426	9,282	2,571	0.4089	0.935	2.243	No	No	Y
BU	KGE	Winfield	5,741,561	13,302	4,064	0.4094	0.943	1.958	No	No	Y
BU	KPL	Winfield	149,481	186	74	0.4386	0.834	2.052	No	No	Y
CV	KGE	Winfield	3,200,471	6,261	1,547	0.5907	0.939	2.156	No	No	Y
CM	WPE2	Dodge	5,235,955	5,871	590	0.5980	0.874	2.610	No	No	
DS	KPL2	Abilene	5,948,265	12,896	4,875	0.7540	0.935	2.490	No	No	
HL	EDE	Independence	852,783	2,394	864	0.7959	0.967	2.570	No	No	Y
HL	KCP	Independence	1,789,116	4,304	1,949	0.5971	0.928	2.280	No	No	Y
HL	KGE	Independence	4,666,484	10,264	3,527	0.6572	0.940	2.491	No	No	Y
LC	KCL	Cottonwood Falls	844,920	2,005	671	0.4814	0.898	2.036	No	No	Y
LC	KGE	Cottonwood Falls	1,628,886	2,525	785	0.4932	0.878	2.099	No	No	Y
LJ	KPL	Leavenworth	5,952,884	14,062	4,412	0.7732	0.937	2.519	No	No	Y
PL	WPE	Norton	1,641,734	1,602	454	0.6849	0.817	2.722	No	No	Y
RH	MWE	Concordia	279,151	189	39	0.3979	0.671	2.127	No	No	Y
SC	KGE	Winfield	3,715,056	7,114	2,001	0.6226	0.934	2.125	No	No	Y
SC	WPE	Winfield	413,168	1,123	212	0.5699	0.831	1.920	No	No	Y
SG	KGE	Hutchinson	6,282,557	14,090	2,706	0.8371	0.942	2.394	No	No	Y
TV	EDE	Independence	73,541	237	76	0.5809	0.924	2.116	No	No	Y
TV	KGE	Independence	597,396	1,395	454	0.7143	0.941	2.371	No	No	Y
TV	KPL	Independence	1,189,895	2,634	753	0.9415	0.959	2.680	No	No	Y

Abreviations Used in Regressions

Cooperative Abreviation	Cooperative Name
AV	Ark Valley
BA	Brown-Atchison
BL	Bluestem
BU	Butler
CM	CMS
CV	Caney Valley
DS	D S & O
FH	Flint Hills
HL	Heartland
LC	Lyon-Coffey
LJ	Leavenworth-Jefferson
NI	Ninnescah
PL	Prairie Land
RA	Radiant
RH	Rolling Hills
SC	Sumner-Cowley
SG	Sedgwick
TV	Twin Valley
VI	Victory

Area Abreviation	Area Name
EDE	Empire District Electric
KCP	Kansas City Power & Light
KGE	Kansas Gas & Electric(Westar)
KPL	Kansas Power & Light(Westar)
STM	St. Marys
SUN	Sunflower
WPE	MKEC (Kansas)

When a 2 is appended to an area abreviation, it signifies that some portion of the load has been removed from the Cooperative/Area data.