

MAY 09 2012

by
State Corporation Commission
of Kansas

STATE OF KANSAS

BEFORE THE KANSAS CORPORATION COMMISSION

Application for Revised Rates, Tariffs, and Rate Design Changes

of

Mid-Kansas Electric Company, LLC

Docket No. 12-MKEE-380-RTS

May 9, 2012

**PREFILED REBUTTAL TESTIMONY
RICHARD J. MACKE
VICE PRESIDENT, ECONOMICS, RATES, AND BUSINESS PLANNING
POWER SYSTEM ENGINEERING, INC.**

**ON BEHALF OF
MID-KANSAS ELECTRIC COMPANY, LLC**

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A. ADJUSTMENTS AND CORRECTIONS TO PREFILED DIRECT TESTIMONY AND EXHIBITS

Q. Are you filing any changes to your prefiled Direct Testimony and Exhibits?

A. Yes. I am including the following adjustments to my previously filed Testimony and Exhibits:

1. I have made three corrections to my present and proposed rate revenue calculations as shown in my prefiled Exhibit RJM-2 and RJM-6 and as identified in Staff Data Request Nos. 202 and 205.
 - a. The first two concern the incorrect present rate being used for two lighting categories. Since there are only two lights served at these rates, the impact is minimal at \$60 per year in the one case and \$118 per year in the other.
 - b. The third is a correction to the formula used to total revenue from the Municipal Service rate classification under both present and proposed rates.

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The formula I used did not include the Customer Charge revenue. The impact of this correction is an increase in present rate revenue of \$20,286.

2. I have updated and corrected the billing units for the Local Access Charge (“LAC”) rate class to reflect units used by Staff and Citizens’ Utility Ratepayer Board (“CURB”) as was provided by Southern Pioneer during the discovery process. This resulted in an increase in LAC Billing Demand and present rate revenue of 12,078 kW and \$24,518, respectively.

3. In response to prefiled direct testimony of Staff witness Ms. Laura Bowman and CURB witness Ms. Andrea Crane, I have modified my determination of income taxes to more clearly include and demonstrate the incremental tax impact of the increase. This increased the income tax expense component of the revenue requirement by \$62,766. The details are shown on page 2 of the attached Exhibit RJM-13.

I have attached the affected exhibits to demonstrate the above changes along with the impacts on the rate increase needed for the Southern Pioneer Division rates.

Q. Please summarize the impact of the above changes on the revenue requirements and rate increase request for the Southern Pioneer Division rates.

A. The impact of the changes noted above are very minimal with regards to the overall rate relief needed, as the net effect is an \$18,140 increase to the increase requested. The following Table 1 illustrates the impact under the proposed DSC Ratemaking Plan utilizing a 1.80 DSC ratio.

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Table 1 Comparison of Direct and Rebuttal Testimony 1.80 DSC With DSC Ratemaking Plan			
Description	Direct Testimony	Rebuttal Testimony	Change
Revenue Requirement	\$65,086,412	\$65,149,178	\$62,766
Revenue	<u>58,973,464</u>	<u>59,018,090</u>	<u>44,626</u>
Requested Increase	\$ 6,112,948	\$ 6,131,09	\$18,140
As Percent of Rate Schedule Revenue	10.5%	10.5%	

Table 2 below illustrates the impact under the 2.00 DSC that I am recommending should the DSC Ratemaking Plan be rejected by the Commission.

Table 2 Comparison of Direct and Rebuttal Testimony 2.00 DSC Without DSC Ratemaking Plan			
Description	Direct Testimony	Rebuttal Testimony	Change
Revenue Requirement	\$66,965,986	\$67,028,753	\$62,766
Revenue	<u>58,973,464</u>	<u>59,018,090</u>	<u>44,626</u>
Requested Increase	\$ 7,992,522	\$ 8,010,663	\$18,140
As Percent of Rate Schedule Revenue	13.7%	13.7%	

Q. Is the impact of your changes significant?

A. No, as the above tables show, the impact on the overall revenue increase is not significant. However, the distribution of the increase between the Southern Pioneer Division retail and 34.5 kV wholesale customers via the increase in the LAC rate schedule is more pronounced. Under the revised analysis, relatively more of the increase is allocated to the 34.5 kV cost of service due to the corrected billing units for the LAC rate class. The cost of providing 34.5 kV service is recovered not only as part of the retail rates but separately from wholesale customers through the Southern Pioneer Division LAC Schedule. The change in billing units increases the allocation of the revenue requirements paid by the wholesale customers and reduces the portion allocated to retail customers and embedded in the retail rates. This result is illustrated in the following Table 3.

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Table 3 Comparison of Direct and Rebuttal Testimony 1.80 DSC With DSC Ratemaking Plan			
Description	Direct Testimony	Rebuttal Testimony	Change
Total Increase	\$6,112,948 10.5%	\$6,131,089 10.5%	\$ 18,140 0.3%
Retail Increase	\$5,871,021 10.2%	\$5,651,821 9.8%	(\$219,200) (3.7%)
LAC Increase	\$241,927 31.0%	\$479,268 59.6%	\$237,341 98.1%

A similar shift occurs under the 2.00 DSC without the DSC Ratemaking Plan recommendation.

Q. Has your recommendation of a DSC Ratemaking Plan changed?

A. No. I continue to recommend that the Commission approve the proposed DSC Ratemaking Plan with a beginning DSC ratio of 1.80. The objections to the proposed DSC Ratemaking Plan are unconvincing and grounded in speculation and in some cases a misunderstanding of what is being proposed. Implementing the DSC Ratemaking Plan reduces the rate increase being requested by Southern Pioneer by nearly 25 percent, to \$6,131,089 or 10.5 percent, versus the request without the DSC Ratemaking Plan.

Absent Commission approval of the proposed DSC Ratemaking Plan, I continue to recommend a rate increase based upon my test year operating expenses and a 2.00 DSC. This increase is \$8,010,663 or 13.7 percent.

B. SUMMARY

Q. Please summarize the rate increase recommendation of Staff.

A. Staff has proposed numerous adjustments to the application and recommends a retail rate increase of \$2,879,566.¹ In addition, Staff recommends a \$173,463 increase in the LAC

¹ Bowman, Direct, p. 3, ln. 18.

1 rate for third-party customers of the Southern Pioneer 34.5 kV facilities.² In total, Staff
2 recommends a \$3,053,029 revenue increase.

3 **Q. How does Staff support this level of recommended rate increase?**

4 A. Staff has made significant adjustments to the Application in the areas of: 1) utilizing a
5 different DSC ratio calculation formula, 2) excluding all income taxes, and 3) excluding
6 various operating expenses. In addition, Staff recommends that the Commission reject the
7 proposed alternative DSC Ratemaking Plan.

8 **Q. Please summarize the rate increase recommendation of the CURB witness Ms.
9 Crane.**

10 A. Ms. Crane recommends the Commission grant a \$1,787,075 rate increase for the Southern
11 Pioneer Division. This is based on achieving a DSC ratio of 1.75 and includes several
12 expense adjustments. CURB recommends the Commission reject the proposed alternative
13 DSC Ratemaking Plan.

14 **Q. Please summarize the recommendations made by Kansas Electric Power
15 Cooperative, Inc. ("KEPCo").**

16 A. KEPCo does not make a specific recommendation concerning the increase allowance but
17 does weigh-in on various components of the case including: 1) the local access rate
18 schedule terms, 2) various components of the revenue requirements, and 3) the DSC
19 Ratemaking Plan.

20 **Q. Please explain the scope of your rebuttal testimony.**

21 A. My rebuttal testimony does not address every issue or recommendation raised in the
22 prefiled direct or cross-answering testimony of KCC Staff, CURB, or KEPCo. My silence
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25 ² Bowman, Direct, p. 18, Ins. 19-21.

1 on particular issues should not be interpreted as acceptance or agreement with such
2 positions offered by the parties.

3 **C. DSC RATEMAKING PLAN**

4 **Q. One of your claimed benefits of the proposed DSC Ratemaking Plan is cost savings**
5 **versus the traditional regulatory model. How much has it cost for Mid-Kansas to file**
6 **and defend this case so far?**

7 A. According to Southern Pioneer, it has incurred costs of \$135,330.62 for direct legal and
8 consulting service through March 31, 2012. This amount is in line with what one would
9 expect for a general rate case application. As per the testimony of Staff witness Andrea
10 Finger, Exhibit No. ANF-7, KCC Staff and CURB expenses were an additional \$49,009
11 through March 30, 2012. The cost of making a rate application is a significant expense for
12 a utility the size of Southern Pioneer.

13 **Q. Do you agree with Ms. Bowman's conclusion on page 16 of her direct testimony that**
14 **Michigan's formula ratemaking plan (i.e., TIER Indexing (now referred to as TIER**
15 **Ratemaking)) is only applicable or relevant for companies in dire need of financial**
16 **assistance?**

17 A. No. While the applicant in the Michigan Public Service Commission ("MPSC") order
18 provided in Ms. Bowman's Exhibit LKB-6 was indeed under financial stress, financial
19 stress was not the basis for TIER ratemaking in that case and is not a prerequisite for TIER
20 ratemaking as it is applied in Michigan today. In that case which was before the MPSC,
21 the MPSC could have taken action to relieve the company's financial stress without TIER
22 ratemaking. In its order, the MPSC outlined its reasons for adopting TIER ratemaking as
23 an experimental program, and the reasons were not predicated on financial stress. It is
24 especially noteworthy that TIER ratemaking would allow the cooperative to maintain
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1 revenue stability, reduce its TIER levels, and ultimately reduce its requested increase by
2 33 percent. The MPSC also noted that TIER ratemaking should result in reductions in the
3 cooperative's legal, consulting, and financing costs, as well as Commission and
4 Commission Staff resources. These are the same benefits Southern Pioneer is seeking in
5 its proposed DSC Ratemaking Plan.

6 **Q. The MPSC order that Ms. Bowman cites (Exhibit LKB-6) refers to TIER indexing as**
7 **an experimental two-year program. What subsequent actions did the MPSC take**
8 **regarding the program, and what is its status today?**

9 A. Shortly after it issued its order in Case Number U-6652 (Exhibit LKB-6), the MPSC
10 approved TIER Indexing for a second cooperative on an experimental basis. After the
11 two-year trial period in 1983, the MPSC revisited TIER Indexing (still under Case
12 Number U-6652); and, with some refinements, renamed the process TIER Ratemaking
13 and made it available to all of Michigan's cooperatives as part of the ratemaking process.
14 The availability of TIER Ratemaking was not preconditioned on the financial situation of
15 the cooperative.

16 **Q. Since TIER Ratemaking was approved for use by all of Michigan's electric**
17 **cooperatives, has the MPSC reevaluated the process?**

18 A. Yes. In November 1995, the MPSC initiated a proceeding in Case Number U-11016 for
19 the purpose of considering changes to the TIER ratemaking process including whether or
20 not it should be continued. This review spawned extensive testimony and exhibits from
21 both the cooperatives and the MPSC Staff which included a 165-page report prepared by
22 Staff documenting its review of cooperative regulation in Michigan. The MPSC ordered
23 that TIER Ratemaking should be continued. Accordingly, TIER Ratemaking remains
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1 available to Michigan's electric cooperatives in substantially the same format since it was
2 first available in 1983.

3 **Q. How do you respond to the testimony of Ms. Crane (p. 12, l. 4) and KEPCo witness**
4 **Mr. Stephen Daniel (p. 31-32) asserting that the DSC Ratemaking Plan proposed by**
5 **Mid-Kansas for the Southern Pioneer Division would result in less control and**
6 **regulatory oversight by the KCC and that it would shift the burden of proof of the**
7 **reasonableness of rates away from the Company?**

8 A. This characterization of the proposed plan is simply incorrect. First, as part of this
9 docket, the Commission will determine the appropriate structure for the DSC Plan. If the
10 Commission agrees that there are benefits to allowing an expedited annual ratemaking
11 process for the Southern Pioneer Division, then the ultimate plan adopted will be
12 established and approved by the Commission in this proceeding. Thus, the structure and
13 the standards for the annual filings will have been fully reviewed and determined to be just
14 and reasonable as a preliminary matter.

15 Second, when each annual filing is made, the Staff has a full opportunity to review it
16 to make sure the rules adopted by the Commission have been followed by the Company.
17 If Staff believes the filing fails to comply with the Commission's rules, Staff can bring the
18 matter before the Commission. Ultimately, if the issue is not resolved, the Commission
19 can set the matter for hearing.

20 Finally, although the parties would expect that the Plan would be in effect for a
21 minimum of five years if approved in this docket, the Commission always retains the
22 power and authority to revisit a prior decision if it believes modification is necessary to
23 protect the public interest.

24 **Q. What about the assertion that the Plan shifts the burden to Staff and interveners?**
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1 A. This argument fails to acknowledge that Mid-Kansas will have already met its initial
2 burden of establishing that the Ratemaking Plan is in the public interest as part of its
3 approval in this docket. The Commission will have already determined that an expedited
4 annual process is beneficial to the customers of Southern Pioneer's Division. In the
5 annual filings, Mid-Kansas will have the burden of presenting the data and information
6 required by the Commission to establish the basis for any rate adjustment under the
7 previously approved formula. If Staff takes the position that Mid-Kansas has failed to
8 comply with the requirements of the Plan as approved by the Commission, the Company
9 has the burden of establishing its compliance. Clearly, the appropriate burden stays with
10 Mid-Kansas.

11 If, however, an entity such as CURB wants to ask the Commission to terminate the
12 DSC Ratemaking Plan prior to the end of the five years adopted by the Commission, then
13 that entity would have the burden of proving that the Plan is no longer just and reasonable
14 and should be discontinued. This is no different than any complaint brought against a
15 Company regarding a Company practice that has previously been reviewed and approved
16 by the Commission.

17 **Q. What about the provision in the proposed Plan that prohibits interveners in the**
18 **process unless Staff files an objection indicating that the annual filing is not in**
19 **compliance with the approved Plan?**

20 A. It must be remembered that one of the primary goals of the DSC Ratemaking Plan is to
21 reduce regulatory expense and lag. This goal is forsaken if the annual filings become
22 nothing more than standard rate cases with interventions, discovery, and full audits. To
23 balance competing interests, the proposed Plan places the obligation upon Staff to review
24 the filing for compliance, and if the filing is in compliance with the standards approved by
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1 the Commission in this case, then it will be expeditiously submitted to the Commission for
2 final approval. If Staff files an objection to the application because its review indicates
3 that the Company has not complied with the Commission's requirements, then other
4 parties can intervene. Again, any interested entity can file a complaint with the
5 Commission at any time regarding the Plan; however, the filing of such a complaint
6 cannot cause a delay in the annual filing unless *the Commission* takes action necessary to
7 delay the filing.

8 **Q. Is the concept of allowing an expedited rate adjustment using a preapproved formula**
9 **a new concept in Kansas?**

10 A. I do not believe so. I am aware that, in Docket No. 127, 140-U, the Commission adopted
11 a simplified filing procedure and expedited review procedure for access charge
12 adjustments for rural telephone companies that was based on a similar concept. I have
13 attached a copy of the process approved by the Commission in an Order dated November
14 19, 1990 (Exhibit RJM-17). I am advised by counsel that this process was later endorsed
15 by the Kansas Legislature in 1996 when it adopted the process as part of the 1996 Kansas
16 Telecommunications Act in K.S.A. 66-2008(d).

17 **Q. Are you aware of any other examples of annual formula-based rate-setting processes**
18 **affecting Kansas rates?**

19 A. Certainly there are formula rate processes in place at the Federal Regulatory Energy
20 Commission ("FERC") for setting wholesale rates charged in Kansas for transmission and
21 generation. For example, Westar Energy, Inc. ("Westar") had a Cost-Based Formula Rate
22 Agreement for Full Requirements Electric Service approved by FERC in Docket No. ER-
23 07-1344 based upon a power contract entered into between Westar and KEPCo. Cost
24 support for the annual adjustments to Westar's rates is based upon Westar's FERC Form 1
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1 and is computed using an established formula. This concept was not objected to by the
2 Kansas Commission -- which was a party to the FERC docket -- and it was ultimately
3 approved by FERC with modifications recommended by non-KEPCo parties to the
4 docket. The concept underlying the DSC Ratemaking Plan proposed by Mid-Kansas for
5 the format of continued regulation of the Southern Pioneer Division rates in this docket is
6 similar.

7 **Q. CURB witness Ms. Crane states that the proposed DSC Ratemaking Plan would**
8 **result in higher costs for ratepayers. Do you agree?**

9 A. No. Ms. Crane's statement that the DSC Plan results in higher costs for ratepayers is
10 speculation, and she has presented no analysis or facts in support of this statement. The
11 facts show that under the DSC Ratemaking Plan, Southern Pioneer Division is requesting
12 a lower increase; lower by \$1,879,574, or about 25 percent, than it would be without the
13 alternative ratemaking plan. This is possible because Southern Pioneer's lender, CoBank,
14 has agreed to reduce its loan covenants in the early years to help moderate the rate
15 increase needs. In turn, Southern Pioneer is able to request a more gradual increase in its
16 rates than would have been required absent the DSC Ratemaking Plan. Southern Pioneer
17 is not requesting, either in this case or at any time during the course of the proposed DSC
18 Ratemaking Plan, higher rates or a higher DSC ratio than it would be requesting absent
19 the plan.

20 **Q. But doesn't CoBank, in its revised loan covenants, actually increase the required**
21 **DSC ratio for Southern Pioneer beyond what it would have been after March 13,**
22 **2016?**

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1 A. Yes, that is true. In exchange for the lower DSC requirement in the initial years, the DSC
2 beginning March 31, 2016 would be 1.50. This compares to CoBank's "standard"
3 requirement of 1.35.

4 **Q. And on page 15, line 17 of her direct testimony Ms. Crane states that this higher DSC**
5 **requirement in the later years more than offsets any savings in the short term. Do**
6 **you agree?**

7 A. No. Once again, Ms. Crane's assertion is speculative and not supported by analysis or
8 facts. There is no evidence that the higher CoBank DSC requirements in the proposed
9 DSC Ratemaking Plan would have adverse impacts on rates. It is important to recognize
10 that the CoBank DSC requirement is a minimum requirement; it is not, and should not be,
11 the level used for setting rates. Rather, rates should be, and are routinely set, based upon a
12 "cushion" above the lender's minimum requirements to account for contingencies and
13 avoiding default. Ms. Crane acknowledges and supports this on page 17, lines 11-12 of
14 her direct testimony. Commission Staff agrees, as can be seen in the testimony of Ms.
15 Bowman, page 13, beginning on line 11.

16 Absent the DSC Ratemaking Plan, Southern Pioneer is requesting that rates be set to
17 achieve a DSC of 2.00. The DSC used in setting rates is not higher under the DSC
18 Ratemaking Plan and is in fact lower during the first three years. Southern Pioneer is
19 willing to accept less of a "cushion" over the minimum DSC requirement because of the
20 benefits of the DSC Ratemaking Plan, which are discussed on pages 25-26 of my prefiled
21 direct testimony. The following Table 4 provides a comparison.

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Table 4 Comparison of Benefits under Recommended DSC Target and CoBank DSC Requirement			
	Recommended DSC Target	CoBank DSC Requirement	Cushion
Without Plan	2.00	1.35	0.65
With Plan			
2012	1.80	1.00	0.80
2013	1.80	1.25	0.55
2014	1.90	1.35	0.55
2015	2.00	1.35	0.65
2016	2.00	1.50	0.50

Q. Please comment on KEPCo witness Mr. Daniel’s criticism on page 29 of his prefiled direct testimony that the DSC Ratemaking Plan would adjust rates on a per-kWh basis without consideration as to the performance of individual rate classes.

A. The DSC Ratemaking Plan is an interim adjustment mechanism and will not fully replace the need to file a class cost of service study. Contrary to Mr. Daniel’s criticism, I actually have not proposed this adjustment be made on a per-kWh basis. I would not necessarily be opposed to using or at least considering the use of a kWh adjustment, however.³ However, in my Exhibit RJM-8, page 3, paragraph 4.i, I propose making a proportionate adjustment such that the distribution of revenue by rate class prior to the adjustment is preserved. Since rates in this case will be designed in consideration of a class cost of service filing, it is reasonable for an interim adjustment to simply distribute any change on a proportionate basis. There is not typically a substantial shift in cost of service over the

³ Many types of interim adjustment mechanisms are applied on a kWh basis because kWh sales data is readily available for all rate classes. For example, even though changes in power cost may include changes in demand related costs, the energy cost adjustment mechanism passed through total changes in power cost on a kWh basis and without evaluating how individual rate classes may have contributed to those changes in demand costs.

1 short term (i.e., three to five years), and to require a cost of service for annual filings
2 would be burdensome and unnecessary.

3 **Q. Are you familiar with any other regulated utilities that make rate adjustments in**
4 **proportion to revenue by rate class?**

5 A. Yes, this approach has frequently been used in Kentucky since 1999 as a means to flow
6 through wholesale rate changes in lieu of a class cost of service study. I have attached as
7 Exhibit RJM-18 the Kentucky Statute KRS 278.455, Regulation 807 KAR 5:007 and an
8 example filing for reference. With regards to this approach used in Kentucky, if a
9 distribution cooperative wishes to make a disproportionate change, it must then file a rate
10 application with a cost of service study. Similarly, in my proposed DSC Ratemaking Plan,
11 if something other than a proportionate allocation of the increase/decrease is filed, then a
12 cost of service study must be filed in support.

13 **Q. On page 29, line 16, Mr. Daniel states that the DSC Plan is not cost based and rates**
14 **should be based on allocated costs. Please comment.**

15 A. There is no dispute about whether rates should be based on allocated costs; however, Mr.
16 Daniel presents no evidence that the rates resulting from the DSC Plan will not be cost
17 based. Mr. Daniel has speculated about a per kWh adjustment and how it may not track
18 costs over time but has not commented, speculative or otherwise, about the reasonableness
19 of using a proportionate allocation as is proposed in Exhibit RJM-8, page 3 of my direct
20 testimony.

21 **D. PAYROLL AND PAYROLL RELATED EXPENSE**

22 **Q. Have you reviewed the payroll adjustment recommended by Staff witness Ms.**
23 **Kristina Luke?**

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1 A. Yes. Ms. Luke has made a \$547,169 adjustment to reduce payroll expenses included in
2 the application.

3 **Q. Do you agree with Staff's payroll adjustment?**

4 A. No. In calculating the adjustment, Staff adjusted out payroll costs associated with shared
5 management costs of Pioneer Electric Cooperative, Inc. ("Pioneer Electric Cooperative")
6 employees. I have confirmed this with Staff. The payroll expense in the Application
7 included both the payroll of Southern Pioneer employees and the allocated portion of the
8 management group shared with Pioneer Electric Cooperative. However, Staff's payroll
9 amount only reflects the adjusted amount for Southern Pioneer employees. By subtracting
10 one from the other, Staff has produced an adjustment that backs out the costs associated
11 with the allocated Pioneer Electric Cooperative employees from the revenue requirement.
12 Until or unless Staff provides a corrected adjustment to payroll, its \$547,169 adjustment
13 should be reversed.

14 **Q. Does this error also carry forward to Staff's payroll related adjustment?**

15 A. Yes. Staff's payroll related costs need to be updated to reflect this correction. Again,
16 absent a corrected adjustment, Staff's \$223,924 reduction to payroll related expenses
17 should be reversed.

18 **Q. What is the combined impact of Staff's payroll and payroll related error?**

19 A. The result of Staff's payroll and payroll related adjustments is an understatement of
20 \$771,093 based on my filed numbers. This is comprised of an understatement of Southern
21 Pioneer's expenses for payroll of \$547,169 and payroll related expenses of \$223,924.
22 Based on Staff's updating of payroll and payroll related costs, this number will likely be
23 different when corrected by Staff.

24 **E. DEPRECIATION EXPENSE**

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1 **Q. Do you have any comments on Ms. Crane's proposed adjustments to depreciation**
2 **expense?**

3 A. Yes. Ms. Crane has double-counted her recommended \$400,915 adjustment to
4 depreciation expense. This is evident when comparing the columns labeled 'CURB Pro
5 Forma Present Rates' and 'CURB Recommendation' columns in Schedule ACC-1. This
6 error has been confirmed with Ms. Crane, and she has also indicated that this error does
7 not affect her total figures or rate increase recommendation. I have reviewed and agree
8 that this error is isolated and that it does not affect the results of her analysis. However, I
9 do disagree with the depreciation rates she recommends using in this case.

10 **Q. Ms. Crane has recommended using the depreciation rates approved by the**
11 **Commission in Docket No. 12-MKEE-191-DRS ("191 Docket") in this instant case.**
12 **Are the depreciation rates from this 191 Docket appropriate for use in this case?**

13 A. No. The referenced docket involved a depreciation rate study conducted for Mid-Kansas
14 and involved only Mid-Kansas' plant (primarily generation and transmission), not the
15 distribution plant of Southern Pioneer. It would be inappropriate to use these depreciation
16 rates for developing the depreciation expense for Southern Pioneer.

17 **Q. What depreciation rates should be used to determine depreciation expense for**
18 **purposes of this rate application?**

19 A. The appropriate rates to use are the ones being used by Southern Pioneer which were
20 approved in Docket No. 09-MKEE-969-RTS ("969 Docket"). This is consistent with my
21 determination of depreciation expense and also with Staff's exhibits.

22 **Q. Have any other parties filed a position on this issue?**
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1 A. Yes. Staff witness Ms. Bowman has filed cross-answering testimony that is consistent
2 with my position that the depreciation rates approved for Mid-Kansas in the 191 Docket
3 are not appropriate to use for this case.

4 **F. ACQUISITION PREMIUM**

5 **Q. On line 27, page 3 of her direct testimony, Staff witness Ms. Andria Finger testifies**
6 **that you included the amortization of the Acquisition Premium (“AP”) above-the-**
7 **line in your filed test year and as such it is included in the cost of service. Is she**
8 **correct?**

9 A. No, Ms. Finger is mistaken. In Schedule E of Exhibit RJM-2, I have adjusted out the
10 amortization of the AP from depreciation and amortization expense, which is the above-
11 the-line account category to which Southern Pioneer books amortization expense. I then
12 included the AP amortization below-the-line on line 25 of Exhibit RJM-2, page 1.

13 **Q. But does including the AP amortization below-the-line on page 1, line 25 of Exhibit**
14 **RJM-2 simply change where the figure is shown rather than actually remove it for**
15 **the purposes of determining the cost of service; i.e., revenue requirement?**

16 A. No. I have applied the CoBank DSC formula; so since this amortization is a noncash
17 expense, I have not included it as a cost to be recovered by Southern Pioneer Division
18 rates. Contrary to Ms. Finger’s claim, my treatment of the AP amortization is actually
19 consistent with Staff’s treatment.

20 **G. LONG-TERM INTEREST AND DEBT SERVICE COSTS**

21 **Q. Has Staff offered testimony on the appropriate amount of debt costs to be included in**
22 **determining the Southern Pioneer Division rate levels?**

23 A. Yes. Staff witness Mr. Adam Gatewood has testified that all of Southern Pioneer’s debt,
24 including the debt to finance the prepayment penalty associated with the RUS buyout,
25

1 should be included. He acknowledges that there is no flexibility to exclude any of
2 Southern Pioneer's debt as it has no shareholders from which to fund such an exclusion.⁴
3 He also emphasizes the importance of including all of Southern Pioneer's interest
4 payments when it comes to building a healthy balance sheet; i.e., equity position.⁵

5 Obviously, I agree with Mr. Gatewood on the importance of including all of Southern
6 Pioneer's interest expense and debt service in the determination of the Southern Pioneer
7 Division rate. It is consistent with my testimony and determination of the rate increase
8 needed. However, the primary reason the cost related to the refinancing of Southern
9 Pioneer's RUS debt should be included in rates is because the decision to refinance is a
10 prudent decision that is in the best interests of Southern Pioneer's customers and the
11 Company.

12 **Q. Ms. Crane objected to the inclusion of the prepayment penalty on the refinance of**
13 **Southern Pioneer's RUS debt. Please comment.**

14 **A.** Southern Pioneer's CFO, Mr. Chantry Scott, has addressed this issue in his direct and
15 rebuttal testimony; however, I would make a couple of observations.

16 First of all, the fact is that Southern Pioneer is required to make debt service payments
17 to CoBank for the full amount of the loan. This includes the financing of the prepayment
18 penalty. Southern Pioneer simply does not have the flexibility that Ms. Crane implies by
19 recommending the exclusion of these costs.

20 Second, Ms. Crane has proposed in her cross-answering testimony to the direct
21 testimony of Staff witness Mr. Gatewood that Southern Pioneer will have funds over and
22 above the minimum requirements to finance these costs that would be excluded from

23 _____
24 ⁴ Gatewood direct, page 2, lines 3-17.

25 ⁵ Gatewood direct, page 4, lines 2-16.

1 rates.⁶ However, after funding these refinancing costs using Ms. Crane's
2 recommendation, the resulting DSC would be only 1.46, which leaves very little cushion
3 above CoBank's 1.35 required minimum to account for uncontrollable and/or unexpected
4 factors such as inflation, weather, economic conditions, etc. Effectively, Ms. Crane is
5 only including a cushion of 0.11 over the minimum DSC required by Southern Pioneer's
6 lender. This is inadequate to address unexpected events, let alone allow Southern Pioneer
7 to improve its equity level; something Staff and even Ms. Crane accept as an important
8 goal.

9 **Q. Has Ms. Crane been consistent in how she has treated this issue in her analysis?**

10 A. No. Although she excludes the interest expense and debt service related to the
11 prepayment penalty, she has still included the full amount of cash capital credits in her
12 DSC calculation. The \$550,474 of cash capital credits received is 100 percent from
13 CoBank and would not have existed absent the refinance. It is incorrect for Ms. Crane to
14 exclude from her analysis the expense associated with the CoBank refinancing, but
15 include the revenue associated with that refinancing.

16 **Q. On the issue of Southern Pioneer's debt costs, KEPCo witness Mr. Daniel questions**
17 **Southern Pioneer's decision to refinance its RUS debt and offers two options to the**
18 **Commission as regards the increased financing costs. Please comment.**

19 A. Mr. Daniel suggests that the Commission could disallow all financing costs in excess of
20 those available from the RUS or that it could allow the higher interest costs but exclude
21 the prepayment penalty. Neither of these options is feasible especially in light of the
22 totality of his testimony. Mr. Daniel is recommending that the Commission set the
23 Southern Pioneer Division rates only at the minimum financial covenants required of its
24

25 ⁶ Crane cross-answering, page 4.

1 lender. This would provide no “cushion” to fund the prepayment penalty, let alone to
2 account for uncontrollable and/or unexpected factors such as inflation, weather, economic
3 conditions, etc.⁷ Under his recommendation, it is puzzling how Southern Pioneer could
4 ever achieve its minimum financial covenants when he is at the same time recommending
5 the exclusion of interest expense and debt service payments. There is no cushion to
6 absorb this even if the Commission were to agree in principle with Mr. Daniel’s
7 hypothetical options.

8 **H. DSC MARGINS**

9 **Q. Please explain the concept of a Debt Service Coverage (DSC) ratio as it applies to this**
10 **rate application.**

11 A. DSC is a measure of Southern Pioneer’s ability to generate sufficient funds to cover the
12 cash requirements of its long-term debt service (i.e., principal and interest) on an annual
13 basis. A ratio of 1.0 would indicate that Southern Pioneer generated only enough cash to
14 cover its long-term debt service.

15 For this rate application, I have recommended that a DSC ratio be used to determine
16 the margin requirements of the total revenue requirement for the Southern Pioneer
17 Division. Staff and CURB have also applied the DSC ratio in determining the total
18 revenue requirement for the Southern Pioneer Division in this case.

19 **Q. Are there different types of DSC ratios, and are all parties in this case recommending**
20 **the same type of DSC?**

21 A. There are three types of DSC ratios used in the industry by lenders; and, no, not all parties
22 are recommending the same type of DSC in this case. The difference between them is
23 how the margin in the numerator of the calculation is determined. On one end of the
24

25 ⁷ Daniel direct, page 28, lines 1-6.

1 spectrum, the Operating DSC (ODSC) only includes operating income in the numerator.
2 On the other end of the spectrum, the DSC includes all non-operating income and
3 expenses. In the middle is the Modified DSC (MDSC) which includes operating income
4 and cash non-operating income. Below is a list with a formula definition of each.

5 Operating Debt Service Coverage (ODSC): Sum of Patronage Capital & **Operating**
6 Margins plus Depreciation and Amortization Expense, plus Long-Term Interest
7 Expense divided by Total Debt Service Payments.

8 Modified Debt Service Coverage (MDSC): Sum of Patronage Capital & **Operating**
9 Margins plus Depreciation and Amortization Expense, plus Long-Term Interest
10 Expense, plus Interest Income, plus Capital Credits/Patronage divided by Total Debt
11 Service Payments

12 Debt Service Coverage (DSC): Sum of Patronage Capital or **Total** Margins plus
13 Depreciation, Amortization and Long-Term Interest Expense divided by Total Debt
14 Service Payments.

15 In this case, the lines are a little blurred because Southern Pioneer's lender, CoBank,
16 calls its loan covenant requirement DSC, but its formula is more similar to what one
17 would expect for a MDSC. Where a distinction is helpful in my rebuttal testimony I will
18 refer to the CoBank DSC definition as the "CoBank DSC." Both in my testimony and that
19 of CURB, it is the CoBank DSC formula that has been used to determine and evaluate the
20 Southern Pioneer Division rates. This is quite different from Staff's use of DSC which is
21 consistent with the traditional meaning but not the same as the CoBank definition. Staff
22 witness Ms. Bowman recognizes and explains this in her direct testimony beginning on
23 page 11, line 14. On line 15, Ms. Bowman characterizes the CoBank DSC as an ODSC;

24
25

1 however, this is not correct. If anything, the CoBank DSC could be construed as MDSC
2 because it includes cash non-operating margins. It is not however an ODSC.

3 The following Table 5 compares where Staff's DSC diverges from the CoBank DSC
4 method used by CURB and in my direct testimony in this case.

5

Item	DSC Staff	CoBank DSC Southern Pioneer and CURB
Noncash Non-Operating Other Inc.	Included: \$1,474,761	Excluded as noncash.
Allocation of Capital Credits	Included: \$642,263	Excluded as noncash.
Cash Capital Credits Received	Excluded	Included: \$550,474
Amort. Prepayment Expense	Included: \$322,880	Excluded as noncash.

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10 **Q. Do you agree with Ms. Bowman's statement on lines 2-4, page 12 that Staff's DSC**
11 **method provides a more encompassing view of Southern Pioneer's financial health**
12 **and its ability to service its debt?**

13 **A. No. Including substantial non-cash margins as Staff has done actually skews one's view**
14 **of Southern Pioneer's financial health. For example, Staff has applied \$1,474,761 in non-**
15 **cash, non-operating income towards meeting Southern Pioneer's 2.00 DSC ratio. There**
16 **are two substantial problems with including this as a source of DSC margins. First, this**
17 **figure represents Southern Pioneer's allocation of the income of Mid-Kansas, which**
18 **Southern Pioneer owns along with five electric cooperatives. Income generated by Mid-**
19 **Kansas should be used to meet loan covenants and/or financial goals of Mid-Kansas and**
20 **should not be double-counted by applying it to meet Southern Pioneer's loan covenants.**
21 **Secondly, \$0 of the Mid-Kansas income allocated to Southern Pioneer is actually received**
22 **in cash as these funds remain with Mid-Kansas. This income clearly cannot be used to**
23 **service debt as proposed by Ms. Bowman, and it should be excluded from the DSC ratio**

1 calculation as has been done in my testimony and the testimony of CURB witness Ms.
2 Crane.

3 **Q. If Staff computed a CoBank DSC based on its recommended increase what would be**
4 **the result?**

5 A. Per Staff's response to Mid-Kansas Data Request No. 10, Staff's recommended increase
6 of \$2,879,566 would result in a CoBank DSC of 1.79. Please reference Exhibit RJM-20.

7 **Q. Is Staff supportive of Southern Pioneer's goal to increase the equity levels in its**
8 **balance sheet?**

9 A. Yes. Ms. Bowman says as much on page 13, lines 13-14 of her direct testimony.

10 **Q. Has Staff made any "accommodations" to demonstrate its support?**

11 A. No. Staff has recommended a traditional DSC of 2.00. Based on the information included
12 with Ms. Bowman's testimony, a 2.00 DSC is actually 5.2 percent below the five-year
13 average DSC of distribution cooperatives in the State of Kansas, which has been 2.11.⁸
14 The 2010 median DSC in the State of Kansas, which is the most recent data available, was
15 2.26 which exceeds Staff's recommendation in this case by over 27 percent.

16 **Q. Does the information attached to Ms. Bowman's testimony also show what has**
17 **happened to the equity level for the cooperatives in Kansas over this time?**

18 A. Yes. While the DSC has increased from 2.00 in 2006 to 2.26 in 2010 (about 3 percent
19 increase per year), the equity level has remained essentially flat; increasing only from
20 46.83 to 47.35 percent, representing only a 0.3 percent compound annual growth rate. In
21 other words, even under an environment of increasing DSC ratios, cooperatives in Kansas
22 have really only been able to maintain their equity levels. Despite this, Staff recommends
23 a below average DSC for Southern Pioneer which has very little equity.

24

25 ⁸ Bowman direct, page 14, lines 5-9.

1 **Q. Given Staff's stated support for Southern Pioneer's goal of growing equity and the**
2 **historical data provided, at what level would you recommend Staff's DSC be set?**

3 A. If the Commission were to accept Staff's DSC calculation methodology, which is
4 inconsistent with CoBank's formula, my testimony, and CURB's testimony, then the DSC
5 should be set at 2.20 rather than 2.00. This will adequately account for Staff's inclusion of
6 substantial noncash income that is not available to service its debt. It will set the Southern
7 Pioneer DSC at only 4.5 percent above the recent five-year average, yet 2.5 percent below
8 the most recent historical year available (2010 at 2.26). If Staff and the Commission are
9 supportive of Southern Pioneer's goal to grow equity, then a DSC that is modestly above
10 the recent five-year average for cooperatives in Kansas would be reasonable.

11 **Q. Please summarize your assessment of Staff's DSC ratio recommendation for this**
12 **case.**

13 A. While Staff claims to be supportive of Southern Pioneer's goal of increasing its equity
14 level, its DSC recommendation stands in contrast. It is recommending a 2.00 DSC which
15 is over 5 percent below the five-year average for cooperatives in Kansas and which is 27
16 percent below the most recent 2010 average DSC of 2.26. The Commission should
17 recognize the inconsistency in Staff's testimony on this matter and support a DSC that will
18 put Southern Pioneer on a path of increasing its equity level. The three options available
19 to the Commission are: 1) a 2.20 DSC under Staff's DSC formula, 2) a 2.00 CoBank
20 DSC, or 3) the proposed DSC Ratemaking Plan that provides for more stable and gradual
21 increases over time and would start at a 1.80 CoBank DSC.

22 **Q. What DSC level is CURB witness Ms. Crane recommending?**

23 A. Ms. Crane recommends a 1.75 CoBank DSC.
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1 **Q. Would Southern Pioneer achieve a 1.75 CoBank DSC under Ms. Crane's**
2 **recommendation?**

3 A. No. Ms. Crane is recommending the exclusion of expenses including debt service costs
4 that are unavoidable for Southern Pioneer. Therefore, if Ms. Crane's positions were
5 accepted, it would result in a CoBank DSC much less than her 1.75 DSC recommendation.

6 **Q. Please explain.**

7 A. Ms. Crane takes issue with including the debt service costs associated with Southern
8 Pioneer's prepayment penalty. However, the fact remains that Southern Pioneer has and
9 will continue to make principal and interest payments on these funds. Therefore, her
10 \$656,937 adjustment to debt service payments is mythical and cannot be realized by
11 Southern Pioneer. On this issue, I agree with Staff witness Mr. Gatewood that it is
12 necessary to include all of Southern Pioneer's debt service costs.⁹ Adjusting Ms. Crane's
13 calculation to include all of Southern Pioneer's debt service costs lowers the CoBank DSC
14 under her recommended rate change to only 1.55.

15 Clearly, Ms. Crane's recommended increase will not produce a 1.75 CoBank DSC for
16 Southern Pioneer. In fact, after adding back actual income tax expense booked in 2010,
17 Southern Pioneer's CoBank DSC would be only 1.37, which is essentially right at the 1.35
18 minimum requirement. This says nothing of any incremental increase in income taxes that
19 would result from a rate increase. Though Ms. Crane may argue that these types of
20 expenses and others she has excluded are the reasons for her cushion over the CoBank
21 minimum, it is clear that she has not allowed adequate cushion given the amount of real
22 expenses she would have excluded from rates.

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25 ⁹ Gatewood direct, page 2, lines 3-17.

1 The Commission should reject Ms. Crane's recommendations as they would
2 immediately put Southern Pioneer in danger of being in violation of its minimum loan
3 covenant. Application of Ms. Crane's recommendations would be a guarantee that
4 another rate application would need to be filed almost immediately after this case is
5 decided; an outcome that is not in the best interests of the Company or its customers.

6 **Q. On the issue of a "cushion," KEPCo witness Mr. Daniel recommends that the**
7 **Commission set the Southern Pioneer Division rates based upon the minimum DSC**
8 **requirement of CoBank, unless something greater is required to achieve the**
9 **minimum equity ratio requirements of CoBank. Please comment.**

10 **A.** Mr. Daniel is recommending that the Commission set the Southern Pioneer Division rates
11 without any cushion. This recommendation is troubling and should be rejected. Setting
12 rates based upon the minimum loan covenants would put Southern Pioneer literally on the
13 edge of default. There would be no cushion to account for uncontrollable and unexpected
14 events such as decreased sales due to economic or weather conditions or increased costs
15 for storms or inflation. Such an event or combination of events could easily drop
16 Southern Pioneer's DSC below the minimum requirements of CoBank, putting it at risk of
17 default.

18 **Q. Prior to this case and during his 42 year consulting career, has Mr. Daniel ever**
19 **recommended that an electric utility base its rates at the lender minimum loan**
20 **covenant requirements?**

21 **A.** Based on his response to Mid-Kansas Data Request No. 16, Mr. Daniel has never made
22 such a recommendation prior to his direct testimony in this case. Please reference Exhibit
23 RJM-19.

24

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1 **Q. Does the filed direct testimony of Commission Staff or CURB agree with Mr.**
2 **Daniel's position to set the Southern Pioneer Division rates upon the more stringent**
3 **of the DSC or equity ratio requirements of CoBank loan covenants?**

4 A. No. Both parties recommend some level of cushion above these minimums. CURB
5 recommends a cushion of 0.40 (1.75 - 1.35 DSC), and Staff recommends a cushion of 0.65
6 (2.00 - 1.35 DSC). I have recommended a cushion of 0.50 under the alternative DSC
7 Ratemaking Plan and 0.65 without it. Mr. Daniel is the only one in this case that is
8 proposing to set Southern Pioneer Division rates at the minimum requirement.

9 **I. INCOME TAXES**

10 **Q. What adjustment has Staff proposed for income taxes?**

11 A. Staff witness Ms. Bowman recommends disallowing both the income tax expense
12 recorded in the test year and the incremental income tax related to the rate increase.¹⁰ In
13 total, Staff has excluded \$2,912,594 of Federal and State income taxes from being
14 recoverable from ratepayers. It is inconceivable why Southern Pioneer would not be
15 allowed to recover this cost of doing business. Company witness Mr. Jim Smith has
16 provided additional testimony on why the Southern Pioneer Division rates need to recoup
17 income taxes and why Staff's recommended pay-as-you go approach presents an
18 intergenerational conflict and should be rejected by the Commission.

19 **Q. Do you agree with KCC witness Ms. Bowman's statement on page 23 of her direct**
20 **testimony that your adjustment for income taxes shown on Exhibit RJM-3, page 2,**
21 **results in a "double dip" or, in other words, includes the actual test year expense**
22 **twice?**

23 A. No, I have not included a double dip of income taxes in my determination of the revenue
24 requirement. The calculation shown on page 2 of Exhibit RJM-3 attempted to calculate

25 ¹⁰ Bowman direct, page 21, line 5.

1 the change in income tax on a marginal basis which, I admit, is confusing and could lead
2 to the appearance of a double dip. To show this adjustment more clearly, I have prepared
3 a revised page 2 of Exhibit RJM-3 which I have attached to my rebuttal as Exhibit RJM-
4 13. Line 2 of this page shows the total \$4,676,528 after tax margin necessary for Southern
5 Pioneer to achieve a DSC ratio of 2.00. Based on that amount, the calculation determines
6 the Federal and State income taxes on lines 4 through 12. The total revised income tax
7 requirement of \$2,975,360 is shown on line 17 (again at the 2.00 DSC level). After
8 subtracting test year income tax expenses of \$1,054,289, the resulting adjustment to
9 recognize the increase in income taxes is \$1,921,071. This adjustment is \$62,766 higher
10 than the original exhibit and supports my conclusion that the original adjustment is
11 reasonable and there is no double dip.

12 **Q. How did you arrive at the DSC base margin shown on line 2 of Exhibit RJM-13, page**
13 **2?**

14 **A.** Using the 2.00 DSC column, the margin requirement is two times the debt service
15 requirement less interest expense, depreciation expense, and amortization expense. Based
16 on page 1 of Exhibit RJM-3, the DSC based margin equals \$11,187,208 (line 9) less
17 \$4,547,758 (line 4) less \$1,940,041 (line 11) less \$322,880 (line 12).

18 **J. LAC TARIFF**

19 **Q. KEPCo witness Mr. Mark Doljac provides testimony regarding the proposed Local**
20 **Access Delivery Service rate schedule (“LAC Schedule”) for the Southern Pioneer**
21 **Division. Please summarize the issues he takes with what has been proposed in your**
22 **testimony and exhibits.**

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1 A. Mr. Doljac raises two concerns with regards to the LAC Schedule as filed in my Exhibits
2 RJM-9, RJM-10, and RJM-11. The first issue is whether the "Monthly Billing Demand"
3 clause is sufficiently clear. The second issue is the "Loss Factor" clause.

4 **Q Please respond to Mr. Doljac's testimony concerning the lack of clarity in the**
5 **proposed LAC Schedule in terms of the definition of Monthly Billing Demand.**

6 A. I understand Mr. Doljac's point and agree with his proposed means of resolving this
7 concern. I have included a revised LAC Schedule that includes revised language. It is
8 attached to my rebuttal testimony as Exhibit RJM-17.

9 **Q. Please respond to Mr. Doljac's testimony concerning the Loss Factors included in the**
10 **proposed LAC Schedule.**

11 A. I agree with Mr. Doljac

12 **Q. Does this conclude your testimony at this time?**

13 A. Yes, it does.
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**RJM-12 - Statement of Operations
- Present Rates**

Statement of Operations
Present Rates
For the Test Year Ended December 31, 2010

(a) Line No.	(b) Description	(c) Actual Test Year ¹	(d) Adjustments ²	(e) Pro Forma Test Year
1	<u>Operating Revenue</u>			
2	Sales of Electricity	\$ 56,761,383	\$ 1,777,901	\$ 58,539,284 ³
3	Other	1,561,507	(1,082,701)	478,806
4	Total Operating Revenue	\$ 58,322,890	\$ 695,200	\$ 59,018,090
5				
6	<u>Operating Expenses</u>			
7	Cost of Purchased Power	\$ 45,368,418	\$ 149,699	\$ 45,518,117 ⁴
8	Transmission - O & M	709,170	11,619	720,789
9	Distribution - Operation	2,401,071	248,117	2,649,188
10	Distribution - Maintenance	1,227,652	145,432	1,373,084
11	Consumer Accounts	1,290,700	158,141	1,448,841
12	Consumer Service & Information	33,938	4,743	38,681
13	Sales	7,615	-	7,615
14	Administrative & General	1,180,208	155,429	1,335,637
15	Depreciation & Amortization	2,201,657	(261,616)	1,940,041
16	Taxes - Property	-	-	-
17	Taxes - Other	1,054,289	-	1,054,289
18	Interest on Long Term Debt	2,438,148	2,109,610	4,547,758
19	Other Interest Expense	792,193	(788,563)	3,630
20	Other Deductions	30,492	322,880	353,372
21	Total Operating Expenses	\$ 58,735,551	\$ 2,255,491	\$ 60,991,042
22	Net Operating Margins	\$ (412,661)	\$ (1,560,292)	\$ (1,972,953)
23	Non-Operating Margins - Interest	80	-	80
24	Income (Loss) from Equity Inv.	1,474,761	-	1,474,761
25	Non-Operating Margins - Other	9,335	(785,459)	(776,124)
26	G&T Capital Credits	-	-	-
27	Other Capital Credits	642,263	-	642,263
28	Extraordinary Items	-	-	-
29	Patronage Capital or Margins	1,713,778	(2,345,750)	(631,972)

¹ Figures for test year ended December, 2010 contained in Workpapers A.

² See Page 2 and 3 for a summary of adjustments and page reference to supporting schedules.

³ See Pages 6 to 11 for calculation of Pro Forma Test Year Revenue under present rates.

⁴ See Page 12 for calculation of Pro Forma Test Year Purchased Power Expense.

**Supporting Adjustment Schedules
Summary of Adjustments**

(a)	(b)	(c)
Description	Page	Amounts
I. Revenues		
Schedule A - Adjustment to Revenue	6	\$ 1,777,901
Schedule J - Other Operating Revenue	20	\$ (1,082,701)
		<u>\$ 695,200</u>
II. Purchased Power Expense		
Schedule B - Purchased Power Expense	12	<u>\$ 149,699</u>
III. Transmission O&M Expense		
Schedule C - Payroll Expense	14	\$ 6,899
Schedule D - Payroll Related Expenses	17	\$ 4,720
		<u>\$ 11,619</u>
IV. Distribution - Operations Expense		
Schedule C - Payroll Expense	14	\$ 147,329
Schedule D - Payroll Related Expenses	17	\$ 100,788
		<u>\$ 248,117</u>
V. Distribution - Maintenance Expense		
Schedule C - Payroll Expense	14	\$ 86,356
Schedule D - Payroll Related Expenses	17	\$ 59,076
		<u>\$ 145,432</u>
VI. Consumer Accounts Expense		
Schedule C - Payroll Expense	14	\$ 93,903
Schedule D - Payroll Related Expenses	17	\$ 64,239
		<u>\$ 158,141</u>

**Supporting Adjustment Schedules
Summary of Adjustments**

(a) Description	(b) Page	(c) Amounts
VII. Consumer Service and Sales Expense		
Schedule C - Payroll Expense	14	\$ 2,816
Schedule D - Payroll Related Expenses	17	\$ 1,927
		<u>\$ 4,743</u>
VIII. Administrative and General Expense		
Schedule C - Payroll Expense	14	\$ 82,395
Schedule D - Payroll Related Expenses	17	\$ 56,367
Schedule G - Rate Case Expense	17	\$ 16,667
		<u>\$ 155,429</u>
IX. Depreciation Expense		
Schedule E - Depreciation Expense	18	<u>\$ (261,616)</u>
X. Interest on Long Term Debt Expense		
Schedule F - Interest on Long Term Debt Expense	19	<u>\$ 2,109,610</u>
XI. Other Interest Expense		
Schedule H - Other Interest Expense	19	<u>\$ (788,563)</u>
XII. Other Deductions		
Schedule K - Other Interest Expense	20	<u>\$ 322,880</u>

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

I. Consumer and Sales Data for Test Year Ended December 31, 2010 (As Recorded)

(a) Line No.	(b) Description	(c) Avg. No. Cons. ¹	(d) Energy Sales ¹ (kWh)	(e) Billing Demand ¹ (kW)	(f) Revenue ¹ (\$)
1	Residential Service (09-RS)				
2	General Use	12,319	122,806,012	N.A.	13,484,233
3	Space Heating	654	7,674,171	N.A.	743,097
4	General Service Small (09-GSS)	2,574	14,939,481	N.A.	1,596,920
5	General Service Large (09-GSL)	1,212	122,546,410	361,888.2	12,549,755
6	General Service Space Heating	43	5,479,989	10,360.7	471,178
7	Industrial Service (09-IS)	8	19,788,591	58,873.9	1,789,164
8	Interruptible Industrial Service (09-INT)	-	-	-	-
9	Real -Time Pricing (RTP)	2	1,402,633	2,567.5	82,550
10	Transmission Level Service (09-STR)	5	388,276,102	574,992.6	23,911,344
11	Municipal Power Service (09-M-I)	139	1,643,833	N.A.	160,251
12	Water Pumping Service (09-WP)	68	5,394,598	N.A.	539,156
13	Irrigation Service (09-IP-I)	23	1,767,980	N.A.	197,825
14	Temporary Service (09-CS)	3	39,520	N.A.	7,303
15	Lighting	4,978	4,488,065	N.A.	748,516
16	Local Access				1,082,701
17	Total ²	17,050	696,247,385	1,008,682.8	56,281,291

¹ Figures for test year ended December, 2010 as reported by Southern Pioneer and contained in Workpapers B.

² Total number of consumers excludes Lighting.

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

I. Weathern Normalized Consumer and Sales Data for Test Year Ended December 31, 2010

(a) Line No.	(b) Description	(c) Avg. No. Cons. ¹	(d) Energy Sales ¹ (kWh)	(e) Billing Demand ¹ (kW)
1	Residential Service (11-RS)			
2	General Use	12,319	121,581,325	N.A.
3	Space Heating	654	7,658,281	N.A.
4	General Service Small (11-GSS)	2,574	15,057,356	N.A.
5	General Service Large (11-GSL)	1,212	123,586,152	364,919.9
6	General Service Space Heating	43	5,524,622	10,440.4
7	Industrial Service (11-IS)	8	19,296,669	57,257.1
8	Interruptible Industrial Service (11-INT)	-	-	-
9	Real Time Pricing (RTP)	2	1,331,218	2,436.7
10	Transmission Level Service (11-STR)	5	388,276,102	574,992.6
11	Municipal Power Service (11-M-I)	139	1,655,611	N.A.
12	Water Pumping Service (11-WP)	68	5,436,218	N.A.
13	Irrigation Service (11-IP-I)	23	1,642,409	N.A.
14	Temporary Service (11-CS)	3	40,022	N.A.
15	Lighting	4,978	4,488,065	N.A.
16		N.A.	N.A.	431,555.6
17	Total ²	17,050	695,574,051	1,010,046.7

¹ Weather normalized figures as contained in Workpaper B.

² Total number of consumers excludes Lighting.

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

II. Consumer and Sales Data for Pro Forma Test Year

(a) Line No.	(b) Description	(c) Avg. No. Cons. ¹	(d) Energy Sales ² (kWh)	(e) Billing Demand (kW)	(f) Revenue ³ (\$)
1	Residential Service (09-RS)				
2	General Use	12,240	120,801,641	N.A.	13,418,928
3	Space Heating	685	8,021,288	N.A.	795,774
4	General Service Small (09-GSS)	2,564	14,998,858	N.A.	1,614,857
5	General Service Large (09-GSL)	1,260	128,480,653	379,372.1	13,325,660
6	General Service Space Heating	43	5,524,622	10,440.4	490,525
7	Industrial Service (09-IS)	8	19,296,669	57,257.1	1,818,321
8	Interruptible Industrial Service (09-INT)	-	-	-	-
9	Real -Time Pricing (RTP)	2	1,331,218	2,436.7	82,550
10	Transmission Level Service (09-STR)	5	388,276,102	574,992.6	24,469,707
11	Municipal Power Service (09-M-I)	147	1,750,898	N.A.	175,112
12	Water Pumping Service (09-WP)	70	5,596,107	N.A.	569,742
13	Irrigation Service (09-IP-I)	23	1,618,606	N.A.	183,388
14	Temporary Service (09-CS)	3	40,022	N.A.	7,542
15	Lighting	4,978	4,488,065	N.A.	783,116
16	Local Access	N.A.	N.A.	396,089.2	804,061
17	Total⁴	17,050	700,224,751	1,024,499.0	58,539,284
	Historical Revenue				<u>56,761,383</u>
	Adjustment				<u>1,777,901</u>

¹ Number of consumers as of Dec 10 .

² Energy sales are based on historical average energy usage per consumer.

³ See Schedule A, pages 7 - 11.

⁴ Total number of consumers excludes Lighting.

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

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

Rate Class	Billing Determinants	Units	Rate	Revenue (\$)
<u>Residential Service (04-RS)</u>				
<u>General Use</u>				
Customer Charge	12,240	cons	\$11.50	1,689,120
Delivery Charge				
Summer - All kWh	54,148,376	kWh	\$0.10491	5,680,706
Winter (Nov-Jun)	66,653,265	kWh	\$0.09410	6,272,072
Energy Cost Adjustment	120,801,641	kWh	(\$0.00185)	(222,970)
				13,418,928
<u>Space Heating</u>				
Customer Charge	685	cons	\$11.50	94,530
Delivery Charge				
Summer - All kWh	2,292,203	kWh	\$0.10491	240,475
Winter (Nov-Jun)				
0-800 kWh	3,323,458	kWh	\$0.09410	312,737
801-5800 kWh	2,383,981	kWh	\$0.06745	160,800
5801 kWh and above	21,646	kWh	\$0.09410	2,037
Energy Cost Adjustment	8,021,288	kWh	(\$0.00185)	(14,805)
				795,774
<u>General Service Small (04-GSS)</u>				
Customer Charge	2,564	cons	\$15.80	486,134
Delivery Charge				
Summer - (July to Oct.)	5,279,112	kWh	\$0.08358	441,228
Winter (Nov-Jun)	9,719,746	kWh	\$0.07358	715,179
Energy Cost Adjustment	14,998,858	kWh	(\$0.00185)	(27,684)
				1,614,857
<u>General Service Large (04-GSL)</u>				
Customer Charge	1,260	cons	\$40.75	616,140
Minimum Charges				483,296
Demand Charge per kW>9				
Summer - (July to Oct.)	147,350.3	kW	\$10.00	1,473,503
Winter (Nov-Jun)	232,021.8	kW	\$8.00	1,856,175
Delivery Charge	128,480,653	kWh	\$0.07109	9,133,690
Energy Cost Adjustment	128,480,653	kWh	(\$0.00185)	(237,144)
				13,325,660

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 (\$)
<u>General Service Space Heating</u>				
Customer Charge		43 cons	\$40.75	21,027
Demand Charge				
Summer - (July to Oct.)	4,836.2	kW	\$10.00	48,362
Winter (Nov-Jun)	5,604.2	kW	\$8.00	44,834
Energy Charge				
GSL	3,943,507	kWh	\$0.07109	280,344
Heating	1,581,115	kWh	\$0.06714	106,156
Energy Cost Adjustment	5,524,622	kWh	(\$0.00185)	(10,197)
				490,525
<u>Industrial Service (09-IS)</u>				
Customer Charge		8 cons	\$100.62	9,660
Demand Charge per kW>10				
Summer - (July to Oct.)	16,830.0	kW	\$12.50	210,375
Winter (Nov-Jun)	40,427.1	kW	\$9.50	384,057
Delivery Charge	19,296,669	kWh	\$0.06477	1,249,845
Energy Cost Adjustment	19,296,669	kWh	(\$0.00185)	(35,617)
				1,818,321
<u>Real-Time Pricing (RTP)</u>				
Customer Charge		2 cons	\$251.55	6,037
Delivery Charge	1,331,218	kWh	\$0.05748	76,513
				82,550
<u>Transmission Level Service (09-STR)</u>				
<u>Service at 34.5 kV Voltage</u>				
Customer Charge		1 cons	\$111.80	1,342
<u>Demand Charge</u>				
Demand Requirements	-	kW	\$6.29	
OATT	-	kW	\$2.72	
Local Access Charge	-	kW	\$2.03	
<u>Energy Charge</u>				
Energy Charge	41,577	kWh	\$0.00990	411
Energy Cost Adjustment	41,577	kWh	\$0.03806	1,582
Delivery Charge	41,577	kWh	\$0.00170	71
<u>Service at 115 kV Voltage</u>				
Customer Charge		4 cons	\$111.80	5,366
<u>Demand Charge</u>				
Demand Requirements	574,993	kW	\$6.29	3,616,703
OATT	574,993	kW	\$2.72	1,565,431
<u>Energy Charge</u>				
Energy Charge	388,234,525	kWh	\$0.00990	3,841,969
Energy Cost Adjustment	388,234,525	kWh	\$0.03806	14,776,833
Delivery Charge	388,234,525	kWh	\$0.00170	659,999
Total STR				24,469,707

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 (\$)
<u>Municipal Power Service (09-M-I)</u>				
Customer Charge		147 cons	\$11.50	20,286
Delivery Charge				
Summer - (July to Oct.)		742,790 kWh	\$0.09603	71,330
Winter (Nov-Jun)		1,008,108 kWh	\$0.08603	86,728
Energy Cost Adjustment		1,750,898 kWh	(\$0.00185)	(3,232)
				175,112
<u>Water Pumping Service (09-WP)</u>				
Customer Charge		70 cons	\$16.21	13,616
Delivery Charge				
Summer - (July to Oct.)		2,519,948 kWh	\$0.10672	268,929
Winter (Nov-Jun)		3,076,159 kWh	\$0.09672	297,526
Energy Cost Adjustment		5,596,107 kWh	(\$0.00185)	(10,329)
				569,742
<u>Irrigation Service (09-IP-I)</u>				
Demand Charge per horsepower contracted per year		1,754 /HP/yr.	\$34.00	59,643
Delivery Charge				
Summer - (July to Oct.)		1,287,982 kWh	\$0.08034	103,477
Winter (Nov-Jun)		330,624 kWh	\$0.07034	23,256
Energy Cost Adjustment		1,618,606 kWh	(\$0.00185)	(2,988)
				183,388
<u>Temporary Service (09-CS)</u>				
Delivery Charge		40,022 kWh	\$0.19030	7,616
plus equipment service chg.				
Energy Cost Adjustment		40,022 kWh	(\$0.00185)	(74)
				7,542
<u>Private Area / Street Lighting (09-PAL-SL-I)</u>				
<u>Private Area Light (Coop owned)</u>				
On Existing Pole				
100 W P.A.L. Cust 0%		592 lights	\$8.74	62,089
100 W P.A.L. Cust 100%		2 lights	\$3.33	80
150 W P.A.L. Cust 0%		28 lights	\$13.89	4,667
200 W P.A.L. Cust 0%		14 lights	\$15.63	2,626
200 W P.A.L. Cust 50%		1 lights	\$10.63	128
On New Pole (Wood)				
100 W P.A.L. Cust 0%		163 lights	\$14.55	28,460
100 W P.A.L. Cust 100%		2 lights	\$3.71	89
150 W P.A.L. Cust 0%		30 lights	\$16.19	5,828
200 W P.A.L. Cust 0%		6 lights	\$17.38	1,251
<u>Flood Lights</u>				
On Existing Pole				
150 W Flood Cust 0%		67 lights	\$16.44	13,218
400 W Flood Cust 0%		176 lights	\$30.19	63,761
400 W Flood Cust 50%		1 lights	\$20.34	244
400 W Flood Cust 100%		1 lights	\$10.96	132
1000 W Flood M.H. Cust 0%		32 lights	\$44.56	17,111
On New Pole (Wood)				
150 W P.A.L. Cust 0%		18 lights	\$18.56	4,009
400 W P.A.L. Cust 0%		82 lights	\$32.28	31,764
1000 W Flood M.H. Cust 0%		8 lights	\$60.49	5,807

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 (\$)
<u>Private Area / Street Lighting (09-PAL-SL-I)</u>				
Continued				
<u>Street Lights</u>				
On Existing Pole				
100 W P.A.L. Cust 0%		28 lights	\$9.69	3,256
150 W P.A.L. Cust 0%		3 lights	\$11.44	412
200 W P.A.L. Cust 0%		3 lights	\$14.07	507
On New Pole (Wood)				
100 W P.A.L. Cust 0%		5 lights	\$14.55	873
200 W P.A.L. Cust 0%		4 lights	\$17.38	834
On Existing Pole				
150 W Cobra Head Cust 0%		1 lights	\$11.44	137
200 W Cobra Head Cust 0%		26 lights	\$14.07	4,390
400 W Cobra Head Cust 0%		5 lights	\$18.84	1,130
400 W Cobra Head Cust 100%		22 lights	\$10.20	2,693
On New Pole (Wood)				
150 W Cobra Head Cust 0%		1 lights	\$18.32	220
200 W Cobra Head Cust 0%		4 lights	\$19.18	921
400 W Cobra Head Cust 0%		7 lights	\$24.72	2,076
On New Pole (Steel)				
100 W Cobra Head Cust 0%		1 lights	\$26.53	318
150 W Cobra Head Cust 0%		1 lights	\$27.83	334
150 W Cobra Head Cust 100%		16 lights	\$5.63	1,081
200 W Cobra Head Cust 0%		17 lights	\$29.40	5,998
<u>Acorn</u>				
100 W HPS Cust 50%		3 lights	\$16.75	603
<u>Vapor Street Lighting Ornamental Service (09-OSL-V-I)</u>				
175 W MV		129 lights	\$10.71	16,579
250 W MV		138 lights	\$12.99	21,511
400 W MV		119 lights	\$17.22	24,590
100 W HPS		439 lights	\$9.69	51,047
150 W HPS		121 lights	\$11.44	16,611
200 W HPS		155 lights	\$14.07	26,170
<u>Controlled Private Area Lighting (04-PAL-I) Frozen</u>				
175 W MV		553 lights	\$9.76	64,767
400 W MV		59 lights	\$18.79	13,303
400 W MV (Flood)		81 lights	\$20.49	19,916
1000 W MV (Flood)		19 lights	\$38.84	8,856
100 W HPS		302 lights	\$8.74	31,674
200 W HPS		30 lights	\$15.63	5,627
150 W HPS (Flood)		100 lights	\$16.44	19,728
400 W HPS (Flood)		92 lights	\$30.19	33,330

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
<u>Street Lighting Service Dusk to Dawn (04-SL-I)</u>				
MV 7000 lumen lamps	1,386	lights	\$10.26	(\$) 170,644
Energy Cost Adjustment	4,488,065	kWh	(\$0.00185)	(8,284)
Total Lighting	5,093	lights		<u>783,116</u>
<u>Local Access Charge (09-LAC)</u>				
Demand Charge	396,089	kW	\$2.03	804,061
Grand Total	700,224,751			<u><u>58,539,284</u></u>

Schedule B
Pro Forma Purchased Power Expense and Adjustment

Mid-Kansas Electric Company, LLC			
Description	Units Purchased ¹	Pro Forma Test Year	
		Rate ²	Amount
Demand Charge	1,234,597 kW-mo.	\$6.29 /kW	\$ 7,765,613
Energy Charge	720,417,017 kWh	\$0.009896 /kWh	\$ 7,129,247
ECA Rate	720,417,017 kWh	\$0.038062 /kWh	\$ 27,420,234
OATT Rate			\$ 3,361,219
Energy 3-2-1 Member Credits			\$ (158,196)
Total	720,417,017 kWh	0.0632 /kWh	\$ 45,518,117
Pro Forma Purchased Power Expense			\$ 45,518,117
Pro Forma Adjustment			\$ 149,699
Historical Test Year Purchased Power Expense			\$ 45,368,418

¹ Per page 6 adjusted for line loss.

² Demand and Energy Rates as approved in Docket No. 09-MKKEE-969-RTS.

Calculation of Pro Forma ECA Factor

(a) Line No.	(b) Category	(c) Amount	(d) Source
1	Total Power Costs	\$ 45,518,117	Exhibit RJM-12, page 12
2	Less Power Costs RTP	\$ 89,905	Exhibit RJM-4, page 13
3	Less Power Costs STR	\$ 24,032,277	Exhibit RJM-4, page 13
4	Less 3-2-1 Credits	\$ (158,196)	Exhibit RJM-12, page 12
5	Total Qualifying Power Costs	\$ 21,554,131	
6			
7	Total kWh Sold	700,224,751 kWh	Exhibit RJM-12, page 6
8	Less kWh Sold RTP	1,331,218 kWh	Exhibit RJM-12, page 6
9	Less kWh Sold STR	388,276,102 kWh	Exhibit RJM-12, page 6
10	Qualifying kWh	310,617,430 kWh	
11			
12	ECA Base Cost per kWh Sold	\$ 0.069391 /kWh	
13			
14	ECA Base	\$ 0.071237 /kWh	Per Docket No. 09-MKEE-969-RTS
15	Pro Forma ECA-2	\$ (0.001846) /kWh	

**Schedule C
Adjustment to Payroll Expense**

I. Adjustments to Payroll Expense

A. Actual wages recorded during the test year.

1. From Jan 1, 2010 to Dec 31, 2010 payroll \$ 3,245,002

B. Total Pro Forma Test Year Payroll Increase -

1. Pro Forma Test Year Payroll \$ 3,820,123

2. Less: Test Year Payroll \$ 3,245,002

II. Summary

	Total
1. Wages booked in Test Year	\$ 3,245,002
2. Adjustments (Schedule C, Part I) Test Year Changes	
a. Increase in Wages	\$ 575,121
Total Adjustments	\$ 575,121
3. Total Pro Forma Test Year Payroll	\$ 3,820,123

V. Allocation of Payroll Adjustment to Expense Categories

Category	Payroll Recorded in Test Year	Allocation Factor	Adjustment
Transmission	\$ 38,927	1.20%	\$ 6,899
Distribution Operations	\$ 831,276	25.62%	\$ 147,329
Distribution Maintenance	\$ 487,244	15.02%	\$ 86,356
Consumer Accounts	\$ 529,826	16.33%	\$ 93,903
Consumer Service	\$ 15,890	0.49%	\$ 2,816
Sales Expense		0.00%	\$ -
Admin. and General	\$ 464,899	14.33%	\$ 82,395
Regulatory Expense	\$ -	0.00%	\$ -
Sub-total	\$ 2,368,061	72.98%	\$ 419,698
Other	\$ 876,941	27.02%	\$ 155,423
Total	\$ 3,245,002	100.00%	\$ 575,121

Schedule D
Adjustment to Payroll Related Expenses

	Total
<u>Total Change in Payroll per Schedule C</u>	\$ 575,121
<u>A. Long & Short Term Disability</u>	
1. Adjustment due to increase in payroll	
a. Rate	1.07%
b. Adjustment	\$ 6,154
2. Adjustment due to increase in rate	
a. Total pro forma payroll	\$ 3,820,123
b. Change in rate	0.00%
c. Adjustment	\$ -
3. Subtotal Long Term Disability	\$ 6,154
<u>B. FICA</u>	
1. Adjustment due to increase in payroll	
a. Rate	7.65%
b. Adjustment	\$ 43,997
2. Adjustment due to increase in rate	
a. Total pro forma payroll	\$ 3,820,123
b. Change in rate	0.00%
c. Adjustment	\$ -
3. Subtotal FICA	\$ 43,997
<u>C. Workmen's Compensation</u>	
1. Adjustment due to increase in payroll	
a. Rate	5.10%
b. Adjustment	\$ 29,331
2. Adjustment due to increase in rate	
a. Total pro forma payroll	\$ 3,820,123
b. Change in rate	0.00%
c. Adjustment	\$ -
3. Subtotal Workmen's Compensation	\$ 29,331

Schedule D
Adjustment to Payroll Related Expenses

	Total
<u>D. Medical/Vision & Gym Expense</u>	
1. Adjustment due to increase in payroll	
a. Rate	30.65%
b. Adjustment	\$ 176,275
2. Adjustment due to increase in rate	
a. Total pro forma payroll	\$ 3,820,123
b. Change in rate	0.00%
c. Adjustment	\$ -
3. Subtotal Hospitalization Expense	\$ 176,275
<u>E. Life Insurance</u>	
1. Adjustment due to increase in payroll	
a. Rate	0.74%
b. Adjustment	\$ 4,256
2. Adjustment due to increase in rate	
a. Total pro forma payroll	\$ 3,820,123
b. Change in rate	0.00%
c. Adjustment	\$ -
3. Subtotal Life Insurance Expense	\$ 4,256
<u>F. State and Federal Unemployment</u>	
1. Adjustment due to increase in payroll	
a. Rate	6.20%
b. Adjustment	\$ 35,657
2. Adjustment due to increase in rate	
a. Total pro forma payroll	\$ 3,820,123
b. Change in rate	0.00%
c. Adjustment	\$ -
3. Subtotal Unemployment	\$ 35,657
<u>G. Retirement and Pension</u>	
1. Adjustment due to increase in payroll	
a. Rate	11.00%
b. Adjustment	\$ 63,263
2. Adjustment due to increase in rate	
a. Total pro forma payroll	\$ 3,820,123
b. Change in rate	0.00%
c. Adjustment	\$ -
3. Subtotal Retirement and Pension	\$ 63,263

**Schedule D
Adjustment to Payroll Related Expenses**

		Total
<u>H. 401K Match</u>		
1.	Adjustment due to increase in payroll	
a.	Rate	6.00%
b.	Adjustment	\$ 34,507
2.	Adjustment due to increase in rate	
a.	Total pro forma payroll	\$ 3,820,123
b.	Change in rate	0.00%
c.	Adjustment	\$ -
3.	Subtotal 401K Match	\$ 34,507
 <u>I. Summary</u>		
		<u>Pro Forma Adj.</u>
1.	Long & ShortTerm Disability	\$ 6,154
2.	Workmen's Compensation	\$ 29,331
3.	Medical/Vision & Gym Expense	\$ 176,275
4.	Life Insurance	\$ 4,256
5.	State and Federal Unemployment	\$ 35,657
6.	Retirement and Pension	\$ 63,263
7.	401K Match	\$ 34,507
8.	Sub-Total	\$ 349,443
9.	FICA	\$ 43,997
10.	Total	\$ 393,440

H. Allocation Payroll Related Expense Adjustments to Expense Categories

Category	Payroll Recorded in Test Year	Allocation Factor	Adjustment
Generation	\$ -	0.00%	\$ -
Transmission	\$ 38,927	1.20%	\$ 4,720
Distribution Operations	\$ 831,276	25.62%	\$ 100,788
Distribution Maintenance	\$ 487,244	15.02%	\$ 59,076
Consumer Accounts	\$ 529,826	16.33%	\$ 64,239
Consumer Service	\$ 15,890	0.49%	\$ 1,927
Sales Expense	\$ -	0.00%	\$ -
Admin. and General	\$ 464,899	14.33%	\$ 56,367
Regulatory Expense	-	0.00%	-
Sub-total	\$ 2,368,061	72.98%	\$ 287,116
Other	\$ 876,941	27.02%	\$ 106,325
Total	\$ 3,245,002	100.00%	\$ 393,440

**Schedule E
Adjustment to Depreciation Expense**

A. Depreciation on Existing Plant

1. Depreciation Expense on Plant as of 5/31/11	\$203,438
2. Less: Amortization of Acquisition Premium	\$65,455
3. Net Depreciation Expense to be Annualized	\$137,983
4. Multiply by 12 Months	12
5. Normalized Depreciation Expense on Existing Plant	\$1,655,796

B. Depreciation on New Plant Added

Description of Plant	Amount	Depreciation Rate	Annual Depreciation Expense
May 31, 2011 WIP	\$ 10,079,634		\$ -
Less: FEMA Reimbursements			
Net Plant Additions as of 5/31/11	\$ 10,079,634	2.820%	\$ 284,246
Additional Plant per budget Jun-Dec.			\$ -
Depreciation Expense	\$ 20,159,268		\$ 284,246

D. Summary

1. Total Depreciation Expense for the Pro Forma Test Year (A + B)	\$ 1,940,041
2. Less: Actual Depreciation Expense for the Test Year	\$ 2,201,657
3. Adjustment to Depreciation Expense	\$ (261,616)

Schedule F
Adjustment to Interest on Long Term Debt Expense

A. Interest on Long-Term Debt

1. Interest Expense on Plant as of 5/31/11	\$295,490 less S/T =	\$247,326
2. Multiply by 12 Months		<u>12</u>
3. Adjusted Interest Expense on Existing Loans		<u>\$ 2,967,913</u>

B. Normalized Interest on Long-Term Debt¹

	<u>Description</u>	<u>Outstanding Bal.</u>	<u>Est. Rate</u>	<u>Int. Expense</u>
1.a.	Refinanced RUS 10/31/2011	<u>\$ 84,688,239</u>	5.37%	<u>\$ 4,547,758</u>
		<u>\$ 84,688,239</u>		<u>\$ 4,547,758</u>
1.b.	Debt Service Payments on Refinanced RUS Debt with 30-year amortization.			\$ 5,743,604

C. Adjustment to Long Term Interest Expense

1. Interest Expense for the Pro Forma Test Year	\$ 4,547,758
2. Interest Expense for the Test Year	<u>\$ 2,438,148</u>
3. Adjustment to Interest on Long Term Debt	<u>\$ 2,109,610</u>

Schedule G
Adjustment for Rate Case Expense

1. Estimated Rate Case Expense	\$ 50,000
2. Amortize Over 3 Years	<u>3</u>
3. Adjustment to A&G for Estimated Rate Case Expense	<u>\$ 16,667</u>

Schedule H
Adjustment to Other Interest Expense

A. Other Interest Expense

1. Other Interest Expense for the Test Year ending December 2010	\$ 792,193
2. Less Interest Expense (1.431.2) for the Test Year ending December 2010	\$ 32,463
3. Less CoBank Interest Expense (1.431.75) for the Test Year ending December 2010	\$ 409,825
4. Less CoBank Interest Expense (1.431.76) for the Test Year ending December 2010	\$ 346,275
2. Other Interest Expense for the Pro Forma Test Year	<u>\$ 3,630</u>
3. Adjustment to Other Interest Expense	<u>\$ (788,563)</u>

¹ Reference Workpaper WP-__.

**Schedule I
Adjustment to Property Tax Expense**

A. Property Taxes

Category	2010	2011	Adjustment
Property taxes paid by category			
Transmission	\$ 422,260	\$ 422,260	\$ -
Distribution Operations	\$ 833,617	\$ 833,617	\$ -
Distribution Maintenance	\$ -	\$ -	\$ -
Consumer Accounts	\$ 20,707	\$ 20,707	\$ -
Customer Service	\$ 135	\$ 135	\$ -
Administrative & General	\$ 17,749	\$ 17,749	\$ -

**Schedule J
Adjustment to Other Operating Revenue**

A. Other Operating Revenue

1. Other Operating Revenue for the Pro Forma Test Year removal LAC Revenue	\$ (1,082,701)
2. Adjustment to Other Operating Revenue	<u>\$ (1,082,701)</u>

**Schedule K
Adjustment to Other Deductions**

A. Other Deductions

1. Premium on RUS Buyout ¹	\$ 9,686,404
2. Amortization Years (Levelized over new loan amortization years)	30
2. Adjustment to Other Deductions Expenses	<u>\$ 322,880</u>

RJM-13 - Revenue Requirements

Determination of Revenue Requirements -- Summary

(a) Line No.	(b) Description	(c)	(d)	(e)
		Dec 31, 2010 Test Year Actual	Present Rates Pro Forma Test Year	Proposed Rates Pro Forma Test Year
Financial Results From Rates				
1	Total Revenue ¹	58,322,890	59,018,090	65,149,178
2	Operating Expense (before interest expense) ¹	56,297,403	56,443,284	56,443,284
3	Net Operating Income (before interest expense) ²	2,025,487	2,574,806	8,705,894
4	Long Term Interest ³	2,438,148	4,547,758	4,547,758
5	Operating TIER (before Tax Requirement) ⁴	0.83	0.57	1.91
Required Increase (Decrease) --2.0 DSC Objective				
6	Margin Requirements			
7	Debt Service Payments ⁵	2,651,712	5,743,604	5,743,604
8	Target DSC ⁶	2.00	2.00	2.00
9	Net Operating Income Required ⁷	5,303,424	11,487,208	11,487,208
10	Less: Non-Operating Income (Cash) ¹	(9,415)	(9,415)	(9,415)
11	Less: Depreciation Expense ¹	(1,416,198)	(1,940,041)	(1,940,041)
12	Less: Other Deductions (Amortizations) ¹	-	(322,880)	(322,880)
13	Less: Cash Capital Credits Received ¹	(401,563)	(550,474)	(550,474)
14	Plus: Federal and State Tax Requirement ⁸	1,054,289	1,921,071	1,921,071
15	Total Revenue Requirements ⁹	60,827,940	67,028,753	67,028,753
16	Revenue From Present Rates			
17	Tariff Revenue ¹	56,761,383	58,539,284	64,670,373
18	Other Operating Revenue ¹	1,561,507	478,806	478,806
19	Total Revenue	58,322,890	59,018,090	65,149,178
20	Required Increase (Decrease) ¹⁰	2,505,050	8,010,663	1,879,575
21	Percent Increase (Decrease) ¹¹	4.4	13.7	2.9
Required Increase (Decrease) --1.8 DSC Objective				
22	Margin Requirements			
23	Debt Service Payments ⁵	2,651,712	5,743,604	5,743,604
24	Target DSC ⁶	1.80	1.80	1.80
25	Net Operating Income Required ¹²	4,773,082	10,338,487	10,338,487
26	Less: Non-Operating Income (Cash) ¹	(9,415)	(9,415)	(9,415)
27	Less: Depreciation Expense ¹	(1,416,198)	(1,940,041)	(1,940,041)
28	Less: Other Deductions (Amortizations) ¹	-	(322,880)	(322,880)
29	Less: Cash Capital Credits Received ¹	(401,563)	(550,474)	(550,474)
30	Plus: Federal and State Tax Requirement ⁸	1,054,289	1,190,217	1,190,217
31	Total Revenue Requirements ¹³	60,297,597	65,149,178	65,149,178
32	Revenue From Present Rates			
33	Tariff Revenue ¹	56,761,383	58,539,284	64,670,373
34	Other Operating Revenue ¹	1,561,507	478,806	478,806
35	Total Revenue	58,322,890	59,018,090	65,149,178
36	Required Increase (Decrease) ¹⁴	1,974,707	6,131,089	0
37	Percent Increase (Decrease) ¹⁵	3.5	10.5	0.0

¹ See Exhibit RJM-2.² Line 1 minus Line 2.³ Reference Exhibit RJM-2, page 1.⁴ Line 3 divided by Line 4.⁵ Exhibit RJM-2, page 19.⁶ 2.0 W/O DSC Ratemaking, 1.8 W/DSC Ratemaking.⁷ Line 7 times Line 8.⁸ See page 2.⁹ Sum of Lines 9 through 14.¹⁰ Line 15 minus Line 19.¹¹ Line 20 divided by Line 17.¹² Line 23 times Line 24.¹³ Sum of Lines 25 through 30.¹⁴ Line 31 minus Line 35.¹⁵ Line 36 divided by Line 33.

Calculation of Federal and State Income Taxes

Line	Description	Ref.	2.0 DSC Amount	1.8 DSC Amount
1	After Tax Operating Margin			
2	Margin Requirements @ Target TIER	Exh. RJM-3	\$ 4,676,528	\$ 3,527,807
3				
4	Federal Income Tax			
5	Effective Tax Rate		34.0%	34.0%
6	Taxable Income - Federal	L2 / (1-L5)	7,085,648	5,345,162
7	Federal Income Tax	L5 * L6	\$ 2,409,120	\$ 1,817,355
8				
9	State Income Tax			
10	Effective Tax Rate		7.4%	7.4%
11	Taxable Income - State (Total)	L6 / (1-L10)	7,651,888	5,772,314
12	Tax at Effective Tax Rate	L10 * L11	\$ 566,240	\$ 427,151
13				
14	Total Income Taxes to be Included in Revenue Requirements			
15	Federal	L7	\$ 2,409,120	\$ 1,817,355
16	State	L12	566,240	427,151
17	Total		\$ 2,975,360	\$ 2,244,506
18	Less: Test Year Income Taxes		1,054,289	1,054,289
19	Increase in Income Taxes		\$ 1,921,071	\$ 1,190,217
20	Tax Multiplier		1.636	1.636

**RJM-14 - Retail Class Cost of
Service**

Cost of Service Summary
Revenue Requirements Summary -- BUNDLED

Line No.	Description	Total	Residential (04-RS)	Residential W/Space Heat (04-RS)	GS Small (04-GSS)	GS Large (04-GSL)	GS Large W/Space Heat (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Temp Service (04-CS)	Lighting 'AL-SL-I, DOL- (PAL-I, SL-I)
1	Revenue Requirements												
2	Revenue Requirements	39,313,593	15,876,898	1,024,273	2,413,153	15,275,419	575,867	2,018,462	247,955	619,698	204,545	7,631	1,049,690
3													
4	Present Rates												
5	Revenue-Present Rates	33,182,966	13,418,928	795,774	1,614,857	13,325,660	490,525	1,818,321	175,112	569,742	183,388	7,542	783,116
6	Revenue Credits	478,806	193,625	11,482	23,301	192,279	7,078	26,237	2,527	8,221	2,646	109	11,300
7		33,661,771	13,612,554	807,256	1,638,158	13,517,940	497,603	1,844,558	177,639	577,963	186,034	7,651	794,415
8													
9	Required Incr./(Decr)	5,651,821	2,264,344	217,017	774,995	1,757,479	78,263	173,905	70,316	41,735	18,511	(20)	255,274
10	Percent	17.03%	16.87%	27.27%	47.99%	13.19%	15.96%	9.56%	40.16%	7.33%	10.09%	(0.27%)	32.60%
11													

Cost of Service Summary
Class Allocation Summary – BUNDLED

Line No.	Category	Total	Residential (04-RS)	Residential W/Space Heat (04-RS)	GS Small (04-GSS)	GS Large (04-GSL)	GS Large W/Space Heat (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Temp Service (04-CS)	Lighting 'AL-SL-I, DOL- (PAL-I, SL-I)
19	Power Supply												
20	Direct												
21	Wholesale Cost												
22	Allocated Cost												
23	Subtotal												
24	Capacity Related												
25	Wholesale Cost	5,715,350	2,103,079	138,435	277,992	2,600,525	79,245	306,115	31,432	85,273	30,196	1,749	61,308
26	Allocated Cost												
27	Subtotal	5,715,350	2,103,079	138,435	277,992	2,600,525	79,245	306,115	31,432	85,273	30,196	1,749	61,308
28	Energy Related												
29	Wholesale Cost	15,680,584	6,098,307	404,931	757,172	6,485,958	278,894	974,134	88,389	282,503	81,710	2,020	226,566
30	Allocated Cost												
31	Subtotal	15,680,584	6,098,307	404,931	757,172	6,485,958	278,894	974,134	88,389	282,503	81,710	2,020	226,566
32	Sub. Power Supply	21,395,934	8,201,386	543,365	1,035,164	9,086,483	358,139	1,280,249	119,821	367,776	111,907	3,769	287,875
33	Transmission												
34	Direct												
35	Capacity	900,579	337,988	22,328	43,566	393,989	13,850	51,159	4,989	14,504	4,720	212	13,273
36	Energy												
37	Allocated Cost												
38	Sub. Transmission	900,579	337,988	22,328	43,566	393,989	13,850	51,159	4,989	14,504	4,720	212	13,273
39	Distribution												
40	Direct	511,785											511,785
41	Consumer	3,396,060	2,087,396	116,819	680,845	396,358	13,527	3,430	48,972	23,320	9,718	512	15,164
42	Capacity	13,109,234	5,250,128	341,761	653,578	5,398,588	190,351	683,624	74,174	214,098	78,200	3,138	221,593
43	Energy												
44	Sub. Distribution	17,017,079	7,337,524	458,580	1,334,423	5,794,946	203,877	687,054	123,145	237,418	87,919	3,650	748,542
45													
46	Total		15,876,898	1,024,273	2,413,153	15,275,419	575,867	2,018,462	247,955	619,698	204,545	7,631	1,049,690

Cost of Service Summary
Rate Design Factors -- BUNDLED

Line No.	Category	Units	Total	Residential (04-RS)	Residential W/Space Heat (04-RS)	GS Small (04-GSS)	GS Large (04-GSL)	GS Large W/Space Heat (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Temp Service (04-CS)	Lighting 'AL-SL-I, DOL (PAL-I, SL-I)	
47	Costs Broken Down by Function														
48	Power Supply														
49	Direct														
50	Wholesale Cost	\$/Mo./cons													
51	Allocated Cost	\$/Mo./cons													
52	Subtotal														
53	Capacity Related														
54	Wholesale Cost	¢/kWh	1.84	1.74	1.73	1.85	2.02	1.43	1.59	1.80	1.52	1.87	4.37	1.37	
55	Allocated Cost	¢/kWh													
56	Subtotal	¢/kWh	1.84	1.74	1.73	1.85	2.02	1.43	1.59	1.80	1.52	1.87	4.37	1.37	
57	Energy Related														
58	Wholesale Cost	¢/kWh	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	
59	Allocated Cost	¢/kWh													
60	Subtotal	¢/kWh	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	
61	Sub. Power Supply	¢/kWh	6.89	6.79	6.77	6.90	7.07	6.48	6.63	6.84	6.57	6.91	9.42	6.41	
62	Transmission														
63	Direct	¢/kWh													
64	Capacity	¢/kWh	0.29	0.28	0.28	0.29	0.31	0.25	0.27	0.28	0.26	0.29	0.53	0.30	
65	Energy	¢/kWh													
66	Allocated Cost	¢/kWh													
67	Sub. Transmission	¢/kWh	0.29	0.28	0.28	0.29	0.31	0.25	0.27	0.28	0.26	0.29	0.53	0.30	
68	Distribution														
69	Direct	\$/Mo./cons	1.98											9.59	
70	Consumer	\$/Mo./cons	13.17	14.21	14.21	22.13	26.21	26.21	35.73	27.76	27.76	35.73	14.21	0.28	
71	Capacity	¢/kWh	4.22	4.35	4.26	4.36	4.20	3.45	3.54	4.24	3.83	4.83	7.84	4.94	
72	Energy	¢/kWh													
73	Sub. Distribution	¢/kWh	5.48	6.07	5.72	8.90	4.51	3.69	3.56	7.03	4.24	5.43	9.12	16.68	
74	Total	¢/kWh		13.14	12.77	16.09	11.89	10.42	10.46	14.16	11.07	12.64	19.07	23.39	
75	Costs Broken Down by Classification														
76	Direct	\$/Mo./cons	1.98											9.59	
77	Consumer	\$/Mo./cons	13.17	14.21	14.21	22.13	26.21	26.21	35.73	27.76	27.76	35.73	14.21	0.28	
78	Capacity	¢/kWh	6.35	6.37	6.26	6.50	6.53	5.13	5.39	6.32	5.61	6.99	12.74	6.60	
79	Energy	¢/kWh	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	5.05	
80	Total	¢/kWh		13.14	12.77	16.09	11.89	10.42	10.46	14.16	11.07	12.64	19.07	23.39	

Classification of Plant in Service -- BUNDLED

Line No.	Acct. No.	Description	Class. Factor	Total	Power Supply Energy Capacity	Transmission Energy Capacity	Dist. Substation Capacity Cons.	Primary Line Capacity Cons.	Line Transf. Capacity Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
1		Intangible Plant											
2	301	Organization	PLNT										
3	302	Franchises and consents	PLNT										
4	303	Miscellaneous intangible plant	PLNT										
5	301-303	Subtotal											
6													
7		Production Plant											
8	310-346	Production Plant	PRODI										
9													
10		Transmission Plant											
11	350-359	Transmission Plant	TRANI	15,251,790		15,251,790							
12													
13		Distribution Plant											
14	360	Land	LAND	40,521			40,521						
15	361	Structures	SUB	101,821			101,821						
16	362	Station	SUB	4,304,136			4,304,136						
17	363	Battery	SUB										
18	364	Poles, towers	PRI	9,786,607				9,786,607					
19	365	OH Cond	PRI	7,727,055				7,727,055					
20	366	UG Conduit	PRI										
21	367	UG Cond	PRI	2,093,998				2,093,998					
22	368	Transf	TRF	5,726,042					5,726,042				
23	369	Services	SERV	1,633,235						1,633,235			
24	370	Meters	MTR	3,989,855							3,989,855		
25	371	Cons Premise	ICON	297,550				297,550					
26	372	Leased Prop	LICON										
27	373	St. Light	STL	1,455,348									
28	360-373	Subtotal		37,156,168			4,446,478	19,905,210	5,726,042	1,633,235	3,989,855		
29													
30		General Plant											
31	389	Land & Land Rights	PLNT	140,161		40,790	11,892	53,235	15,314	4,368	10,671		
32	390	Structures and Improve.	PLNT	1,677,028		488,050	142,285	636,957	183,230	52,263	127,673		
33	391	Office Furniture & Equip.	PLNT	389,975		113,491	33,087	148,117	42,608	12,153	29,689		
34	392	Transportation & Equipment	PLNT	2,807,946		817,170	238,236	1,066,494	306,793	87,506	213,771		
35	393	Stores Equipment	PLNT	212,624		61,878	18,040	80,757	23,231	6,626	16,187		
36	394	Tool, Shop & Garage Equip.	PLNT	22,193		6,459	1,883	8,429	2,425	692	1,690		
37	395	Laboratory Equipment	PLNT	173,952		50,624	14,759	66,069	19,006	5,421	13,243		
38	396	Power Operated Equipment	PLNT										
39	397	Communication Equipment	PLNT	387,539		112,782	32,880	147,192	42,342	12,077	29,504		
40	398	Miscellaneous Equipment	PLNT	41,426		12,056	3,515	15,734	4,526	1,291	3,154		
41	399	Other tangible property	PLNT										
42	389-399	Subtotal		5,852,844		1,703,298	496,576	2,222,985	639,476	182,397	445,581		
43													
44		Total Plant		58,260,802		16,955,088	4,943,054	22,128,195	6,365,518	1,815,632	4,433,436		

Classification of Plant in Service – BUNDLED

Line No.	Acct. No.	Description	Class. Factor	Total	Residential	Residential	GS Small	GS Large	GS Large	Industrial	Municipal	Water	Irrigation	Temp	Lighting
					(04-RS) Direct	W/Space Heat (04-RS) Direct	(04-GSS) Direct	(04-GSL) Direct	W/Space Heat (04-Rider 1) Direct	(04-IS) Direct	(04-M-I) Direct	Pumping (04-WP) Direct	(04-IP-I) Direct	(04-CS) Direct	AL-SL-I, DOI (PAL-I, SL-I) Direct
1		Intangible Plant													
2	301	Organization	PLNT												
3	302	Franchises and consents	PLNT												
4	303	Miscellaneous intangible plant	PLNT												
5	301-303	Subtotal													
6															
7		Production Plant													
8	310-346	Production Plant	PRODI												
9															
10		Transmission Plant													
11	350-359	Transmission Plant	TRAN1	15,251,790											
12															
13		Distribution Plant													
14	360	Land	LAND	40,521											
15	361	Structures	SUB	101,821											
16	362	Station	SUB	4,304,136											
17	363	Battery	SUB												
18	364	Poles, towers	PRI	9,786,607											
19	365	OH Cond	PRI	7,727,055											
20	366	UG Conduit	PRI												
21	367	UG Cond	PRI	2,093,998											
22	368	Transf	TRF	5,726,042											
23	369	Services	SERV	1,633,235											
24	370	Meters	MTR	3,989,855											
25	371	Cons Premise	ICON	297,550											
26	372	Leased Prop	LICON												
27	373	St. Light	STL	1,455,348											1,455,348
28	360-373	Subtotal		37,156,168											1,455,348
29															
30		General Plant													
31	389	Land & Land Rights	PLNT	140,161											3,892
32	390	Structures and Improve.	PLNT	1,677,028											46,570
33	391	Office Furniture & Equip.	PLNT	389,975											10,829
34	392	Transportation & Equipment	PLNT	2,807,946											77,976
35	393	Stores Equipment	PLNT	212,624											5,904
36	394	Tool, Shop & Garage Equip.	PLNT	22,193											616
37	395	Laboratory Equipment	PLNT	173,952											4,831
38	396	Power Operated Equipment	PLNT												
39	397	Communication Equipment	PLNT	387,539											10,762
40	398	Miscellaneous Equipment	PLNT	41,426											1,150
41	399	Other tangible property	PLNT												
42	389-399	Subtotal		5,852,844											162,531
43															
44		Total Plant		58,260,802											1,617,879

Classification of Revenue Requirements -- BUNDLED

Line No.	Acct. No.	Description	Class. Factor	Total	Power Supply Energy	Power Supply Capacity	Transmission Energy	Transmission Capacity	Dist. Substation Capacity	Dist. Substation Cons.	Primary Line Capacity	Primary Line Cons.	Line Transf. Capacity	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue	
1		Power Supply																	
2		Production																	
3	500-557	Fuel	FUEL																
4	500-557	Non-Fuel O&M - Demand	PROD1																
5	500-557	Non-Fuel O&M - Energy	PROD1																
6		Subtotal - Production																	
7		Purchases																	
8	555	Direct Assign. Chgs (Cr.)																	
9	555	Substation Charges	SUB																
10	555	Demand Charges	PURKW-1	5,715,350		5,715,350													
11	555	Summer	PURKW-2																
12	555	Winter	PURKW-3																
13	555	Other	PURKW-4																
14	555	Energy Charges	PURKWH-1	15,680,584	15,680,584														
15	555	On-Peak	PURKWH-2																
16	555	Off-Peak	PURKWH-3																
17	555	Revenue Related Charges	REV																
18		Subtotal - Purchases		21,395,934	15,680,584	5,715,350													
19	500-557	Total Power Supply		21,395,934	15,680,584	5,715,350													
20																			
21		Transmission																	
22	560-573	Operation & Maintenance	TRAN1	451,527			451,527												
23	555	Transmission - G&T Charges	TRAN2																
24		Total Transmission		451,527			451,527												
25																			
26		Distribution		44,540															
27	580	Oper. Super & Eng.	EX1	216,130					32,457		173,725					5,272			
28	581	Load Dispatch	EX1																
29	582	Oper. Station	SUB	251,847					251,847										
30	583	Oper. OH Line	PRI	1,144,604							1,144,604								
31	584	Oper. UG Line	PRI	144,245							144,245								
32	585	Oper. St. Lighting	STL	36,283															
33	586	Oper. Meters	MTR	40,904															
34	587	Oper. Cons. Install	ICON	59,134							59,134								40,904
35	588	Oper. Misc. Oper.	EX1	684,364					102,775		550,090								16,692
36	589	Rents	EX1																
37	590	Main. Super. & Eng.	EX2	267,559					18,863		231,494		793						2,621
38	591	Main. Structure	SUB																
39	592	Main. Station	SUB	60,933					60,933										
40	593	Main. OH Line	PRI	717,655							717,655								
41	594	Main. UG Line	PRI	30,141							30,141								
42	595	Main. Line Transf.	TRF	2,560									2,560						
43	596	Main. St. Lighting	STL	44,540															
44	597	Main. Meters	MTR	8,467															8,467
45	598	Main. Misc. Dist.	EX2	169,549					11,953		146,696		502						1,661
46	580-598	Subtotal		3,878,914					478,828		3,197,783		3,855						75,617

Classification of Revenue Requirements – BUNDLED

Line No.	Acct. No.	Description	Class. Factor	Total	Residential	Residential	GS Small	GS Large	GS Large	Industrial	Municipal	Water	Irrigation	Temp	Lighting
					(04-RS)	W/Space Heat (04-RS)	(04-GSS)	(04-GSL)	W/Space Heat (04-Rider 1)	(04-IS)	(04-M-1)	(04-WP)	(04-IP-1)	(04-CS)	AL-SL-I, DOL (PAL-I, SL-I)
1		Power Supply													
2		Production													
3	500-557	Fuel	FUEL												
4	500-557	Non-Fuel O&M - Demand	PROD1												
5	500-557	Non-Fuel O&M - Energy	PROD1												
6		Subtotal - Production													
7		Purchases													
8	555	Direct Assign. Chgs (Cr.)													
9	555	Substation Charges	SUB												
10	555	Demand Charges	PURKW-1	5,715,350											
11	555	Summer	PURKW-2												
12	555	Winter	PURKW-3												
13	555	Other	PURKW-4												
14	555	Energy Charges	PURKWH-1	15,680,584											
15	555	On-Peak	PURKWH-2												
16	555	Off-Peak	PURKWH-3												
17	555	Revenue Related Charges	REV												
18		Subtotal - Purchases		21,395,934											
19	500-557	Total Power Supply		21,395,934											
20															
21		Transmission													
22	560-573	Operation & Maintenance	TRAN1	451,527											
23	555	Transmission - G&T Charges	TRAN2												
24		Total Transmission		451,527											
25															
26		Distribution		44,540											
27	580	Oper. Super & Eng.	EX1	216,130											4,676
28	581	Load Dispatch	EX1												
29	582	Oper. Station	SUB	251,847											
30	583	Oper. OH Line	PRI	1,144,604											
31	584	Oper. UG Line	PRI	144,245											
32	585	Oper. St. Lighting	STL	36,283											36,283
33	586	Oper. Meters	MTR	40,904											
34	587	Oper. Cons. Install	ICON	59,134											
35	588	Oper. Misc. Oper.	EX1	684,364											14,806
36	589	Rents	EX1												
37	590	Main. Super. & Eng.	EX2	267,559											13,788
38	591	Main. Structure	SUB												
39	592	Main. Station	SUB	60,933											
40	593	Main. OH Line	PRI	717,655											
41	594	Main. UG Line	PRI	30,141											
42	595	Main. Line Transf.	TRF	2,560											
43	596	Main. St. Lighting	STL	44,540											44,540
44	597	Main. Meters	MTR	8,467											
45	598	Main. Misc. Dist.	EX2	169,549											8,737
46	580-598	Subtotal		3,878,914											122,831

Classification of Revenue Requirements – BUNDLED
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Power Supply		Transmission		Dist. Substation		Primary Line		Line Transf.		Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
					Energy	Capacity	Energy	Capacity	Capacity	Cons.	Capacity	Cons.	Capacity	Cons.				
47		Consumer Acct., Service & Sales																
48		Consumer Accounting																
49	901	Supervision	CACC															
50	902	Meter Reading Expense	CACC	186,808													186,808	
51	903	Records & Collections	CACC	1,121,008													1,121,008	
52	904	Uncollectible Accounts	CACC	117,781													117,781	
53	905	Misc. Customer Account	CACC	23,244													23,244	
54		Subtotal		1,448,841													1,448,841	
55																		
56		Consumer Service & Info.																
57	907	Supervision	CS															
58	908	Customer Assistance	CS	24,652													24,652	
59	909	Info. & Instruction	CS															
60	910	Misc. Cust Serv. & Info	CS	14,029													14,029	
61		Subtotal		38,681													38,681	
62																		
63		Sales																
64	911	Supervision	SALES															
65	912	Demonstrating & Selling	SALES	7,461													7,461	
66	913	Advertising	SALES	154													154	
67	916	Misc. Sales	SALES															
68		Subtotal		7,615													7,615	
69																		
70		Prorated Operating Expenses																
71	920-	Administrative & General																
72	932	Power Supply	EX6-PS															
73		Transmission	EX6-TR															
74		Distribution	EX6-D	1,255,619				111,876		747,146		901			17,667		349,331	
75		Subtotal - A&G		1,255,619				111,876		747,146		901			17,667		349,331	
76																		
77	408	Other Taxes																
78		Power Supply	EX6-PS															
79		Transmission	EX6-TR															
80		Distribution	REV	1,054,289													1,054,289	
81		Subtotal - Other Taxes		1,054,289													1,054,289	
82																		
83	421-	Miscellaneous Expense																
84	426,431	Power Supply	EX6-PS															
85		Transmission	EX6-TR															
86		Distribution	EX6-D	325,399				28,993		193,626		233			4,579		90,530	
87		Subtotal - Misc. Expense		325,399				28,993		193,626		233			4,579		90,530	

Classification of Revenue Requirements – BUNDLED
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Residential	Residential	GS Small	GS Large	GS Large	Industrial	Municipal	Water	Irrigation	Temp	Lighting	
					(04-RS) Direct	(04-RS) Direct	(04-GSS) Direct	(04-GSL) Direct	(04-Rider 1) Direct	(04-IS) Direct	(04-M-I) Direct	(04-WP) Direct	(04-IP-I) Direct	(04-CS) Direct	(PAL-I, SL-I) Direct	
47		Consumer Acct., Service & Sales														
48		Consumer Accounting														
49	901	Supervision	CACC													
50	902	Meter Reading Expense	CACC	186,808												
51	903	Records & Collections	CACC	1,121,008												
52	904	Uncollectible Accounts	CACC	117,781												
53	905	Misc. Customer Account	CACC	23,244												
54		Subtotal		1,448,841												
55																
56		Consumer Service & Info.														
57	907	Supervision	CS													
58	908	Customer Assistance	CS	24,652												
59	909	Info. & Instruction	CS													
60	910	Misc. Cust Serv. & Info	CS	14,029												
61		Subtotal		38,681												
62																
63		Sales														
64	911	Supervision	SALES													
65	912	Demonstrating & Selling	SALES	7,461												
66	913	Advertising	SALES	154												
67	916	Misc. Sales	SALES													
68		Subtotal		7,615												
69																
70		Prorated Operating Expenses														
71	920-	Administrative & General														
72	932	Power Supply	EX6-PS													
73		Transmission	EX6-TR													
74		Distribution	EX6-D	1,255,619												28,699
75		Subtotal - A&G		1,255,619												28,699
76																
77	408	Other Taxes														
78		Power Supply	EX6-PS													
79		Transmission	EX6-TR													
80		Distribution	REV	1,054,289	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
81		Subtotal - Other Taxes		1,054,289												
82																
83	421-	Miscellaneous Expense														
84	426,431	Power Supply	EX6-PS													
85		Transmission	EX6-TR													
86		Distribution	EX6-D	325,399												7,437
87		Subtotal - Misc. Expense		325,399												7,437

Classification of Revenue Requirements -- BUNDLED
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Power Supply Energy	Power Supply Capacity	Transmission Energy	Transmission Capacity	Dist. Substation Capacity	Dist. Substation Cons.	Primary Line Capacity	Primary Line Cons.	Line Transf. Capacity	Line Transf. Cons.	Second. & Serv. Cons.	Meter Cons.	Acct. & Serv. Cons.	Revenue
88		Fixed Charges																
89	403-	Depreciation																
90	407	Power Supply	PROPLNT															
91		Transmission	TRNPLNT	449,053			449,053											
92		Distribution	DSTPLNT	1,286,213					153,921		689,047		198,215		56,537	138,114		
93		Subtotal - Depreciation		1,735,265			449,053		153,921		689,047		198,215		56,537	138,114		
94																		
95	408	Property Taxes																
96		Power Supply	REV															
97		Transmission	REV															
98		Distribution	REV															
99		Subtotal - Property Taxes																
100																		
101	427	Interest-LT																
102		Power Supply	PROPLNT															
103		Transmission	TRNPLNT															
104		Distribution	DSTPLNT	4,069,354					486,980		2,180,024		627,118		178,872	436,970		
105		Subtotal - Interest-LT		4,069,354					486,980		2,180,024		627,118		178,872	436,970		
106																		
107		Required Margin																
108		Power Supply	PROPLNT															
109		Transmission	TRNPLNT															
110		Distribution	DSTPLNT	3,652,155					437,053		1,956,523		562,824		160,534	392,171		
111		Subtotal - Required Margin		3,652,155					437,053		1,956,523		562,824		160,534	392,171		
112																		
113		Summary of Revenue Requirements																
114		Power Supply		21,395,934	15,680,584	5,715,350												
115		Transmission		900,579			900,579											
116		Distribution		17,017,079				1,697,651		8,964,148		1,393,146		395,943	1,065,118	1,934,999	1,054,289	
117		Total Revenue Required		39,313,592	15,680,584	5,715,350	900,579	1,697,651		8,964,148		1,393,146		395,943	1,065,118	1,934,999	1,054,289	

Classification of Revenue Requirements – BUNDLED
(Continued)

Line No.	Acct. No.	Description	Class. Factor	Total	Residential		GS Small (04-GSS)	GS Large (04-GSL)	GS Large		Industrial (04-IS)	Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Temp Service (04-CS)	Lighting AL-SL-I, DOL (PAL-I, SL-I)
					Residential (04-RS) Direct	W/Space Heat (04-RS) Direct			W/Space Heat (04-Rider 1) Direct	Direct						
88		Fixed Charges														
89	403-	Depreciation														
90	407	Power Supply	PROPLNT													
91		Transmission	TRNPLNT	449,053												
92		Distribution	DSTPLNT	1,286,213												50,379
93		Subtotal - Depreciation		1,735,265												50,379
94																
95	408	Property Taxes														
96		Power Supply	REV	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
97		Transmission	REV	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
98		Distribution	REV	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.
99		Subtotal - Property Taxes														
100																
101	427	Interest-LT														
102		Power Supply	PROPLNT													
103		Transmission	TRNPLNT													
104		Distribution	DSTPLNT	4,069,354												159,390
105		Subtotal - Interest-LT		4,069,354												159,390
106																
107		Required Margin														
108		Power Supply	PROPLNT													
109		Transmission	TRNPLNT													
110		Distribution	DSTPLNT	3,652,155												143,049
111		Subtotal - Required Margin		3,652,155												143,049
112																
113		Summary of Revenue Requirements														
114		Power Supply		21,395,934												
115		Transmission		900,579												
116		Distribution		17,017,079												511,785
117		Total Revenue Required		39,313,592												511,785

Schedule B
Adjusted Statement of Operations
and Revenue Requirements

(a) Line No.	(b) Description	(c) Total System ¹	(d) Adjustment ²	(e) LAC Revenue Credits ³	(e) Adjusted System
		(\$)	(\$)		(\$)
Operating Revenue					
1	Sales of Electricity	58,539,284	(24,552,257)	(804,061)	33,182,966
2	Other	478,806			478,806
3	Total Operating Revenue	59,018,090	(24,552,257)		33,661,771
Operating Expenses					
5	Cost of Purchased Power				
6	Demand	11,126,832	(5,411,482)		5,715,350
7	Energy	34,391,285	(18,710,701)		15,680,584
8	Transmission - O & M	720,789	-	(269,262)	451,527
9	Distribution - Operation	2,649,188	(71,679)		2,577,509
10	Distribution - Maintenance	1,373,084	(71,679)		1,301,404
11	Consumer Accounts	1,448,841	-		1,448,841
12	Consumer Service & Information	38,681	-		38,681
13	Sales	7,615	-		7,615
14	Administrative & General	1,335,637	(71,679)	(8,338)	1,255,619
15	Depreciation & Amortization	1,940,041	(71,679)	(133,097)	1,735,265
16	Taxes - Property	-	-		-
17	Taxes - Other	1,054,289	-		1,054,289
18	Other Interest Expense	3,630	-		3,630
19	Other Deductions	353,372	-	(31,604)	321,769
20	Total Operating				
21	Term Interest)	56,443,284	(24,408,899)	(442,301)	31,592,084
22	Long Term Interest	4,547,758	(71,679)	(406,725)	4,069,354
23	Required Margin ⁴	4,158,136	(71,679)	(434,302)	3,652,155
24	Revenue Requirements	65,149,178	(24,552,257)	(1,283,329)	39,313,592

¹ See Exhibit RJM-2, page 1.

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

³ Credits related to revenue generated by the Local Access Rate developed in Exhibit RJM-5.

⁴ Required Net Operating Income less Long Term Interest.

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

1. Revenue ¹	Present (\$)	Proposed (\$)
a. Real -Time Pricing (RTP)	= 82,550	= 82,550
b. Transmission Level Service (04-STR)	= 24,469,707	= 24,536,890
d. Total -- Revenue	= <u>24,552,257</u>	= <u>24,619,440</u>
2. Expenses		
a. Purchased Power Expenses ²		
Energy Charges:		
Real -Time Pricing (RTP)		
Energy 1,418,005 kWh x \$0.063403 /kWh	=	89,905
Transmission Level Service (04-STR)		
Energy 388,276,102 kWh x \$0.047958 /kWh	=	18,620,795
	Subtotal -- Energy Expenses	<u>18,710,701</u>
Demand Charges:		
Transmission Level Service (04-STR)		
OATT 600,440 kWh x \$2.72 /kWh	=	1,634,713
Demand 600,440 kW x \$6.29 /kW	=	<u>3,776,769</u>
	Subtotal -- Demand Expenses	<u>5,411,482</u>
	Total -- Purchased Power Expenses	<u>24,122,182</u>
b. Distribution - Operation	=	71,679 ³
c. Distribution - Maintenance	=	71,679 ³
d. Administrative and General	=	71,679 ³
e. Depreciation	=	71,679 ³
f. Interest	=	71,679 ³
g. Margin Requirements	=	71,679 ³
h. Subtotal		<u>430,075</u>
i. Total -- Expenses		<u>\$ 24,552,257</u>

¹ From Exhibit RJM-2, Schedule A.

² From Exhibit RJM-2, Schedule B.

³ Split remainder of revenue approximately equal between Distribution Operation and Maintenance, Administration and General, Depreciation, Interest and Margin Requirements.

Summary of Classification Factors – BUNDLED

Line No.	Name	Description	Source	Total	Power Supply		Transmission		Dist. Substation		Primary Line		Line Transf.		Second.	Meter	Acct.	Revenue
					Energy	Cap.	Energy	Capacity	Cap.	Cons.	Cap.	Cons.	Cap.	Cons.	& Serv. Cons.	Cons.	& Serv. Cons.	
<u>Classification Factor Data</u>																		
1	PROPLNT	Production Plant	Plant															
2	TRNPLNT	Transmission Plant	Plant	15,251,790			15,251,790											
3	DSTPLNT	Distribution Plant	Plant	37,156,168					4,446,478		19,905,210		5,726,042		1,633,235	3,989,855		
4	PLNT	Prod, Trans, Dist. Subtotal	Plant	52,407,958			15,251,790		4,446,478		19,905,210		5,726,042		1,633,235	3,989,855		
5	EX1	Assigned Dist. Oper. Exp.	Rev Req	1,677,016					251,847		1,347,982					40,904		
6	EX2	Assigned Dist. Main. Exp.	Rev Req	864,296					60,933		747,796		2,560			8,467		
7	EX3	Dist. Oper. & Main.	Rev Req	3,878,914					478,828		3,197,783		3,855			75,617		
8	EX4	Assigned O & M Exp.	Rev Req	27,221,512	15,680,584	5,715,350	451,527	478,828		3,197,783		3,855				75,617	1,495,137	
9	EX4-PS	Power Supply	Rev Req	21,395,934	15,680,584	5,715,350										75,617	1,495,137	
10	EX4-TR	Transmission	Rev Req	451,527			451,527											
11	EX4-D	Distribution	Rev Req	5,374,051					478,828		3,197,783		3,855			75,617	1,495,137	
12	EX5	Rev. Req. Less Margin	Rev Req	34,116,556	15,680,584	5,715,350	900,579	1,119,729		6,066,854		829,187		235,409	650,701	1,495,137	1,054,289	
13	EX5-PS	Power Supply	Rev Req	22,450,223	15,680,584	5,715,350												1,054,289
14	EX5-TR	Transmission	Rev Req	900,579			900,579											
15	EX5-D	Distribution	Rev Req	10,765,753					1,119,729		6,066,854		829,187		235,409	650,701	1,495,137	

Summary of Classification Factors – BUNDLED

Line No.	Name	Description	Source	Total	Residential	Residential	GS Small	GS Large	GS Large	Industrial	Municipal	Water	Water	Temp
					(04-RS)	W/Space Heat (04-RS)	(04-GSS)	(04-GSL)	W/Space Heat (04-Rider 1)	(04-IS)	(04-M-1)	(04-WP)	(04-IP-1)	(04-CS)
					Direct	Direct	Direct	Direct	Direct	Direct	Direct	Direct	Direct	Direct
<u>Classification Factor Data</u>														
1	PROPLNT	Production Plant	Plant											
2	TRNPLNT	Transmission Plant	Plant	15,251,790										
3	DSTPLNT	Distribution Plant	Plant	37,156,168										
4	PLNT	Prod, Trans, Dist. Subtotal	Plant	52,407,958										
5	EX1	Assigned Dist. Oper. Exp.	Rev Req	1,677,016										
6	EX2	Assigned Dist. Main. Exp.	Rev Req	864,296										
7	EX3	Dist. Oper. & Main.	Rev Req	3,878,914										
8	EX4	Assigned O & M Exp.	Rev Req	27,221,512										
9	EX4-PS	Power Supply	Rev Req	21,395,934										
10	EX4-TR	Transmission	Rev Req	451,527										
11	EX4-D	Distribution	Rev Req	5,374,051										
12	EX5	Rev. Req. Less Margin	Rev Req	34,116,556										
13	EX5-PS	Power Supply	Rev Req	22,450,223										
14	EX5-TR	Transmission	Rev Req	900,579										
15	EX5-D	Distribution	Rev Req	10,765,753										

Summary of Classification Factors - BUNDLED

Line No.	Name	Description	Source	Total	Power Supply		Transmission		Dist. Substation		Primary Line		Line Transf.		Second.	Meter	Acct.	Revenue
					Energy	Cap.	Energy	Capacity	Cap.	Cons.	Cap.	Cons.	Cons.	Cons.	Cons.			
16	Classification Factors																	
17	CACC	Consumer Accounting	Input	1.000000														1.000000
18	CS	Customer Service	Input	1.000000														1.000000
19	CS-PS	Cust. Service - Pwr. Supply	Input															
20	CS-TR	Cust. Service - Transmission	Input															
21	CS-D	Cust. Service - Distribution	Input	1.000000														1.000000
22	SALES	Sales	Input	1.000000														1.000000
23	SALES-PS	Sales - Power Supply	Input															
24	SALES-TR	Sales - Transmission	Input															
25	SALES-D	Sales - Distribution	Input	1.000000														1.000000
26	PROPLNT	Production Plant	Plant															
27	TRNPLNT	Transmission Plant	Plant	1.000000				1.000000										
28	DSTPLNT	Distribution Plant	Plant	1.000000						0.119670		0.535718		0.154107		0.043956	0.107381	
29	PLNT	Prod, Trans, Dist. Subtotal	Plant	1.000000				0.291020		0.084844		0.379813		0.109259		0.031164	0.076131	
30	EX1	Assigned Dist. Oper. Exp.	Rev Req	1.000000						0.150175		0.803798						0.024391
31	EX2	Assigned Dist. Main. Exp.	Rev Req	1.000000						0.070500		0.865208		0.002962				0.009796
32	EX3	Dist. Oper. & Main.	Rev Req	1.000000						0.123444		0.824402		0.000994				0.019494
33	EX4	Assigned O & M Exp.	Rev Req	1.000000	0.576036	0.209957			0.016587	0.017590		0.117473		0.000142				0.054925
34	EX4-PS	Power Supply	Rev Req	0.785994	0.576036	0.209957												
35	EX4-TR	Transmission	Rev Req	0.016587				0.016587										
36	EX4-D	Distribution	Rev Req	0.197419						0.017590		0.117473		0.000142				0.054925
37	EX5	Rev. Req. Less Margin	Rev Req	1.000000	0.459618	0.167524		0.026397		0.032821		0.177827		0.024305		0.006900	0.019073	0.043824
38	EX5-PS	Power Supply	Rev Req	0.653045	0.459618	0.167524												0.030903
39	EX5-TR	Transmission	Rev Req	0.026397				0.026397										
40	EX5-D	Distribution	Rev Req	0.315558						0.032821		0.177827		0.024305		0.006900	0.019073	0.043824
41	EX6	A&G Classification	Input	1.000000						0.089100		0.595041		0.000717				0.278214
42	EX6-PS	Power Supply	Input															
43	EX6-TR	Transmission	Input															
44	EX6-D	Distribution	Input	1.000000						0.089100		0.595041		0.000717				0.278214
45	FUEL	Fuel	Input															
46	ICON	Install Cons. Prem.	Input	1.000000								1.000000						
47	LAND	Land & Land Rights	Input	1.000000						1.000000								
48	LICON	Leased Property	Input	1.000000								1.000000						
49	MTR	Meters	Input	1.000000														1.000000
50	PRI	Primary Line	Input	1.000000								1.000000						
51	PROD1	Production Plant	Input															
52	PROD2	Production O & M	Input															
53	PURTR-1	Trans. Capacity	Input	1.000000						1.000000								
54	PURTR-2	Trans. Energy	Input	1.000000	1.000000													
55	PURKW-1	Purchased Power Capacity	Input	1.000000		1.000000												
56	PURKW-2	Summer	Input	1.000000		1.000000												
57	PURKW-3	Winter	Input	1.000000		1.000000												
58	PURKW-4	Other	Input	1.000000		1.000000												
59	PURKWH-1	Purchased Power Energy	Input	1.000000	1.000000													
60	PURKWH-2	On-Peak	Input	1.000000	1.000000													
61	PURKWH-3	Off-Peak	Input	1.000000	1.000000													
60	SERV	Services	Input	1.000000														1.000000
61	STL	Street Lighting	Input															
62	SUB	Substation	Input	1.000000						1.000000								
63	TRAN1	Transmission Plant	Input	1.000000						1.000000								
64	TRAN2	Transmission Purchases	Input															
65	TRF	Line Transf.	Input	1.000000										1.000000				
66	REV	Revenue Related	Input	1.000000														1.000000
67	USER01	User Defined 01	Input															
68	USER02	User Defined 02	Input															
69	USER03	User Defined 03	Input															

Summary of Classification Factors – BUNDLED

Line No.	Name	Description	Source	Total	Residential	Residential	GS Small	GS Large	GS Large	Industrial	Municipal	Water	Temp
					(04-RS) Direct	(04-RS) Direct	(04-GSS) Direct	(04-GSL) Direct	(04-Rider 1) Direct	(04-IS) Direct	(04-M-I) Direct	(04-WP) Direct	(04-IP-I) Direct
16	Classification Factors												
17	CACC	Consumer Accounting	Input	1.000000									
18	CS	Customer Service	Input	1.000000									
19	CS-PS	Cust. Service - Pwr. Supply	Input										
20	CS-TR	Cust. Service - Transmission	Input										
21	CS-D	Cust. Service - Distribution	Input	1.000000									
22	SALES	Sales	Input	1.000000									
23	SALES-PS	Sales - Power Supply	Input										
24	SALES-TR	Sales - Transmission	Input										
25	SALES-D	Sales - Distribution	Input	1.000000									
26	PROPLNT	Production Plant	Plant										
27	TRNPLNT	Transmission Plant	Plant	1.000000									
28	DSTPLNT	Distribution Plant	Plant	1.000000									
29	PLNT	Prod, Trans, Dist. Subtotal	Plant	1.000000									
30	EX1	Assigned Dist. Oper. Exp.	Rev Req	1.000000									
31	EX2	Assigned Dist. Main. Exp.	Rev Req	1.000000									
32	EX3	Dist. Oper. & Main.	Rev Req	1.000000									
33	EX4	Assigned O & M Exp.	Rev Req	1.000000									
34	EX4-PS	Power Supply	Rev Req	0.785994									
35	EX4-TR	Transmission	Rev Req	0.016587									
36	EX4-D	Distribution	Rev Req	0.197419									
37	EX5	Rev. Req. Less Margin	Rev Req	1.000000									
38	EX5-PS	Power Supply	Rev Req	0.658045									
39	EX5-TR	Transmission	Rev Req	0.026397									
40	EX5-D	Distribution	Rev Req	0.315558									
41	EX6	A&G Classification	Input	1.000000									
42	EX6-PS	Power Supply	Input										
43	EX6-TR	Transmission	Input										
44	EX6-D	Distribution	Input	1.000000									
45	FUEL	Fuel	Input										
46	ICON	Install Cons. Prem.	Input	1.000000									
47	LAND	Land & Land Rights	Input	1.000000									
48	LICON	Leased Property	Input	1.000000									
49	MTR	Meters	Input	1.000000									
50	PRI	Primary Line	Input	1.000000									
51	PROD1	Production Plant	Input										
52	PROD2	Production O & M	Input										
53	PURTR-1	Trans. Capacity	Input	1.000000									
54	PURTR-2	Trans. Energy	Input	1.000000									
55	PURKW-1	Purchased Power Capacity	Input	1.000000									
56	PURKW-2	Summer	Input	1.000000									
57	PURKW-3	Winter	Input	1.000000									
58	PURKW-4	Other	Input	1.000000									
59	PURKWH-1	Purchased Power Energy	Input	1.000000									
60	PURKWH-2	On-Peak	Input	1.000000									
61	PURKWH-3	Off-Peak	Input	1.000000									
60	SERV	Services	Input	1.000000									
61	STL	Street Lighting	Input										
62	SUB	Substation	Input	1.000000									
63	TRANI	Transmission Plant	Input	1.000000									
64	TRAN2	Transmission Purchases	Input										
65	TRF	Line Transf.	Input	1.000000									
66	REV	Revenue Related	Input	1.000000									
67	USER01	User Defined 01	Input										
68	USER02	User Defined 02	Input										
69	USER03	User Defined 03	Input										

Summary of Allocation of Revenue Requirements to Rate Classes – BUNDLED

Line No.	Cost Classification	Alloc. Factor	Total	Residential				GS Large		Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Temp Service (04-CS)
				Residential (04-RS)	W/Space Heat (04-RS)	GS Small (04-GSS)	GS Large (04-GSL)	W/Space Heat (04-Rider 1)	Industrial (04-IS)				
1	Power Supply												
2	Wholesale Power												
3	Direct Assigned Charges (Credits)	Direct											
4	Demand Related	D7	5,715,350	2,103,079	138,435	277,992	2,600,525	79,245	306,115	31,432	85,273	30,196	1,749
5	Demand Related - Summer	D4											
6	Demand Related - Winter	D5											
7	Demand Related - Other	D6											
8	Subtotal - Demand		5,715,350	2,103,079	138,435	277,992	2,600,525	79,245	306,115	31,432	85,273	30,196	1,749
9	Energy Related	E1	15,680,584	6,098,307	404,931	757,172	6,485,958	278,894	974,134	88,389	282,503	81,710	2,020
10	Energy Related - On-Peak	E2											
11	Energy Related - Off-Peak	E3											
12	Subtotal - Energy		15,680,584	6,098,307	404,931	757,172	6,485,958	278,894	974,134	88,389	282,503	81,710	2,020
13	Revenue Related	R2											
14	Subtotal - Wholesale		21,395,934	8,201,386	543,365	1,035,164	9,086,483	358,139	1,280,249	119,821	367,776	111,907	3,769
15	Allocated Overhead & Margin												
16	Direct Related	Direct											
17	Revenue Related	R2											
18	Demand Related	D7											
19	Energy Related	E1											
20	Subtotal - Allocated												
21	Subtotal - Power Supply		21,395,934	8,201,386	543,365	1,035,164	9,086,483	358,139	1,280,249	119,821	367,776	111,907	3,769
22													
23	Transmission												
24	Direct Assigned	Direct											
25	Demand Related	D9	900,579	337,988	22,328	43,566	393,989	13,850	51,159	4,989	14,504	4,720	212
26	Energy Related	E1											
27	Subtotal-Transmission		900,579	337,988	22,328	43,566	393,989	13,850	51,159	4,989	14,504	4,720	212
28	Allocated Overhead & Margin												
29	Direct Related	Direct											
30	Revenue Related	R2											
31	Demand Related	D9											
32	Energy Related	E1											
33	Subtotal - Allocated												
34	Subtotal - Transmission		900,579	337,988	22,328	43,566	393,989	13,850	51,159	4,989	14,504	4,720	212
35													
36	Distribution												
37	Power Supply	-Energy											
38	Dist. Sub.	-Capacity	1,697,651	637,130	42,089	82,125	742,696	26,109	96,439	9,405	27,341	8,898	399
39	Dist. Sub.	-Consumer											
40	Primary Line	-Capacity	8,964,148	3,364,253	222,245	433,644	3,921,675	137,862	509,228	49,659	144,372	46,983	2,108
41	Primary Line	-Consumer											
42	Line Transf.	-Capacity	1,393,146	776,189	55,145	85,888	361,834	14,900	30,802	10,239	24,230	15,855	286
43	Line Transf.	-Consumer											
44	Sec. & Serv.	-Consumer	395,943	268,018	14,999	63,804	39,886	1,361	290	3,219	1,533	820	66
45	Meter	-Consumer	1,065,118	436,880	24,450	327,439	214,155	7,308	2,237	29,149	13,881	6,337	107
46	Acct. & Serv.	-Consumer	1,934,999	1,382,498	77,370	289,602	142,316	4,857	904	16,604	7,906	2,560	339
47	Revenue Related	-Revenue	1,054,289	472,556	22,282	51,921	372,384	11,480	47,155	4,871	18,155	6,465	345
48	Direct Assigned	Direct	511,785										
49	Subtotal - Distribution		17,017,079	7,337,524	458,580	1,334,423	5,794,946	203,877	687,054	123,145	237,418	87,919	3,650
50	Total		39,313,593	15,876,898	1,024,273	2,413,153	15,275,419	575,867	2,018,462	247,955	619,698	204,545	7,631

Allocation of Plant in Service To Rate Classes – BUNDLED

Line No.	Acct. No.	Description	Class. Factor	Total	Residential (04-RS)	Residential W/Space Heat (04-RS)	GS Small (04-GSS)	GS Large (04-GSL)	GS Large W/Space Heat (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-1)	Water Pumping (04-WP)	Irrigation (04-IP-1)	Temp Service (04-CS)
1		Intangible Plant												
2	301	Organization	PLNT											
3	302	Franchises and consents	PLNT											
4	303	Miscellaneous intangible plant	PLNT											
5	301-303	Subtotal	PLNT											
6														
7		Production Plant												
8	310-346	Production Plant	PRODI											
9														
10		Transmission Plant												
11	350-359	Transmission Plant	TRAN1	15,251,790	5,612,207	369,423	741,841	6,939,673	211,471	816,887	83,879	227,558	80,581	4,667
12														
13		Distribution Plant												
14	360	Land	LAND	40,521	14,911	981	1,971	18,437	562	2,170	223	605	214	12
15	361	Structures	SUB	101,821	37,467	2,466	4,953	46,329	1,412	5,454	560	1,519	538	31
16	362	Station	SUB	4,304,136	1,583,794	104,253	209,351	1,958,413	59,678	230,530	23,671	64,218	22,740	1,317
17	363	Battery	SUB											
18	364	Poles, towers	PRI	9,786,607	3,672,923	242,636	473,431	4,281,487	150,511	555,950	54,215	157,618	51,293	2,302
19	365	OH Cond	PRI	7,727,055	2,899,971	191,574	373,799	3,380,466	118,837	438,953	42,806	124,448	40,499	1,817
20	366	UG Conduit	PRI											
21	367	UG Cond	PRI	2,093,998	785,879	51,916	101,298	916,091	32,204	118,954	11,600	33,725	10,975	492
22	368	Transf	TRF	5,726,042	3,190,255	226,656	353,015	1,487,194	61,242	126,603	42,083	99,591	65,166	1,176
23	369	Services	SERV	1,633,235	1,105,553	61,871	263,186	164,529	5,615	1,194	13,277	6,323	3,384	271
24	370	Meters	MTR	3,989,855	1,636,522	91,586	1,226,564	802,211	27,377	8,379	109,191	51,996	23,740	401
25	371	Cons Premise	ICON	297,550	111,671	7,377	14,394	130,173	4,576	16,903	1,648	4,792	1,560	70
26	372	Leased Prop	LICON											
27	373	St. Light	STL	1,455,348										
28	360-373	Subtotal		37,156,168	15,038,945	981,316	3,021,962	13,185,331	462,015	1,505,089	299,274	544,833	220,108	7,890
29														
30		General Plant												
31	389	Land & Land Rights	PLNT	140,161	55,230	3,612	10,066	53,823	1,801	6,210	1,025	2,066	804	34
32	390	Structures and Improve.	PLNT	1,677,028	660,826	43,223	120,440	643,990	21,551	74,302	12,261	24,716	9,622	402
33	391	Office Furniture & Equip.	PLNT	389,975	153,668	10,051	28,007	149,753	5,012	17,278	2,851	5,747	2,237	93
34	392	Transportation & Equipment	PLNT	2,807,946	1,106,460	72,371	201,659	1,078,270	36,084	124,408	20,529	41,384	16,110	673
35	393	Stores Equipment	PLNT	212,624	83,784	5,480	15,270	81,649	2,732	9,420	1,554	3,134	1,220	51
36	394	Tool, Shop & Garage Equip.	PLNT	22,193	8,745	572	1,594	8,522	285	983	162	327	127	5
37	395	Laboratory Equipment	PLNT	173,952	68,545	4,483	12,493	66,799	2,235	7,707	1,272	2,564	998	42
38	396	Power Operated Equipment	PLNT											
39	397	Communication Equipment	PLNT	387,539	152,708	9,988	27,832	148,818	4,980	17,170	2,833	5,712	2,223	93
40	398	Miscellaneous Equipment	PLNT	41,426	16,324	1,068	2,975	15,908	532	1,835	303	611	238	10
41	399	Other tangible property	PLNT											
42	389-399	Subtotal		5,852,844	2,306,290	150,849	420,336	2,247,531	75,214	259,315	42,790	86,260	33,580	1,402
43														
44		Total Plant		58,260,802	22,957,442	1,501,588	4,184,139	22,372,535	748,699	2,581,292	425,943	858,651	334,269	13,959

Allocation of Revenue Requirements to Rate Classes -- BUNDLED

Line No.	Acct. No.	Description	Class. Factor	Total	Residential (04-RS)	Residential W/Space Heat (04-RS)	GS Small (04-GSS)	GS Large (04-GSL)	GS Large W/Space Heat (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-1)	Water Pumping (04-WP)	Irrigation (04-IP-1)	Temp Service (04-CS)
1		Power Supply												
2		Production												
3	500-557		FUEL											
4	500-557	Non-Fuel O&M - Demand	PRODI											
5	500-557	Non-Fuel O&M - Energy	PRODI											
6		Subtotal - Production												
7		Purchases												
8	555	Direct Assign. Chgs (Cr.)												
9	555	Substation Charges	PURSUB											
10	555	Demand Charges	PURKW-1	5,715,350	2,103,079	138,435	277,992	2,600,525	79,245	306,115	31,432	85,273	30,196	1,749
11	555	Summer	PURKW-2											
12	555	Winter	PURKW-3											
13	555	Other	PURKW-4											
14		Total Demand		5,715,350	2,103,079	138,435	277,992	2,600,525	79,245	306,115	31,432	85,273	30,196	1,749
15	555	Energy Charges	PURKWH-1	15,680,584	6,098,307	404,931	757,172	6,485,958	278,894	974,134	88,389	282,503	81,710	2,020
16	555	On-Peak	PURKWH-2											
17	555	Off-Peak	PURKWH-3											
18		Total Energy		15,680,584	6,098,307	404,931	757,172	6,485,958	278,894	974,134	88,389	282,503	81,710	2,020
19	555	Revenue Related Charges	REVENUE											
20		Subtotal - Purchases		21,395,934	8,201,386	543,365	1,035,164	9,086,483	358,139	1,280,249	119,821	367,776	111,907	3,769
21	500-557	Total Power Supply		21,395,934	8,201,386	543,365	1,035,164	9,086,483	358,139	1,280,249	119,821	367,776	111,907	3,769
22		Transmission												
23	560-573	Operation & Maintenance	TRAN1	451,527	169,458	11,195	21,843	197,536	6,944	25,650	2,501	7,272	2,367	106
24	555	Transmission - G&T Charges	TRAN2											
25		Total Transmission		451,527	169,458	11,195	21,843	197,536	6,944	25,650	2,501	7,272	2,367	106
26		Distribution												
27	580	Oper. Super & Eng.	EX1	216,130	79,543	5,233	11,595	91,261	3,207	11,724	1,286	3,389	1,112	49
28	581	Load Dispatch	EX1											
29	582	Oper. Station	SUB	251,847	94,518	6,244	12,183	110,179	3,873	14,307	1,395	4,056	1,320	59
30	583	Oper. OH Line	PRI	1,144,604	429,571	28,378	55,371	500,746	17,603	65,022	6,341	18,434	5,999	269
31	584	Oper. UG Line	PRI	144,245	54,135	3,576	6,978	63,105	2,218	8,194	799	2,323	756	34
32	585	Oper. St. Lighting	STL	36,283										
33	586	Oper. Meters	MTR	40,904	16,778	939	12,575	8,224	281	86	1,119	533	243	4
34	587	Oper. Cons. Install	ICON	59,134	22,193	1,466	2,861	25,870	909	3,359	328	952	310	14
35	588	Oper. Misc. Oper.	EX1	684,364	251,868	16,569	36,714	288,974	10,155	37,123	4,074	10,732	3,521	155
36	589	Rents	EX1											
37	590	Main. Super. & Eng.	EX2	267,559	95,476	6,299	12,966	110,260	3,877	14,245	1,464	4,080	1,337	59
38	591	Main. Structure	SUB											
39	592	Main. Station	SUB	60,933	22,868	1,511	2,948	26,657	937	3,461	338	981	319	14
40	593	Main. OH Line	PRI	717,655	269,337	17,793	34,717	313,963	11,037	40,768	3,976	11,558	3,761	169
41	594	Main. UG Line	PRI	30,141	11,312	747	1,458	13,186	464	1,712	167	485	158	7
42	595	Main. Line Transf.	TRF	2,560	1,426	101	158	665	27	57	19	45	29	1
43	596	Main. St. Lighting	STL	44,540										
44	597	Main. Meters	MTR	8,467	3,473	194	2,603	1,702	58	18	232	110	50	1
45	598	Main. Misc. Dist.	EX2	169,549	60,502	3,991	8,216	69,871	2,457	9,027	928	2,585	847	38
46	580-598	Subtotal		3,878,914	1,412,999	93,041	201,341	1,624,665	57,104	209,102	22,465	60,266	19,764	873

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

Line No.	Acct. No.	Description	Class. Factor	Total	Residential		GS Small (04-GSS)	GS Large (04-GSL)	GS Large		Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Temp Service (04-CS)
					(04-RS)	W/Space Heat (04-RS)			W/Space Heat (04-Rider 1)	Industrial (04-IS)				
47		Consumer Acct., Service & Sales												
48		Consumer Accounting												
49	901	Supervision	CACC											
50	902	Meter Reading Expense	CACC	186,808	133,469	7,469	27,959	13,739	469	87	1,603	763	247	33
51	903	Records & Collections	CACC	1,121,008	800,926	44,823	167,776	82,448	2,814	523	9,619	4,580	1,483	196
52	904	Uncollectible Accounts	CACC	117,781	84,151	4,709	17,628	8,663	296	55	1,011	481	156	21
53	905	Misc. Customer Account	CACC	23,244	16,607	929	3,479	1,710	58	11	199	95	31	4
54		Subtotal		1,448,841	1,035,153	57,931	216,841	106,560	3,637	677	12,432	5,920	1,917	254
55		Consumer Service & Info.												
56	907	Supervision	CS											
57	908	Customer Assistance	CS	24,652	17,613	986	3,689	1,813	62	12	212	101	33	4
58	909	Info. & Instruction	CS											
59	910	Misc. Cust Serv. & Info	CS	14,029	10,023	561	2,100	1,032	35	7	120	57	19	2
60		Subtotal		38,681	27,636	1,547	5,789	2,845	97	18	332	158	51	7
61		Sales												
62	911	Supervision	SALES											
63	912	Demonstrating & Selling	SALES	7,461	5,331	298	1,117	549	19	3	64	30	10	1
64	913	Advertising	SALES	154	110	6	23	11	0	0	1	1	0	0
65	916	Misc. Sales	SALES											
66		Subtotal		7,615	5,441	304	1,140	560	19	4	65	31	10	1
67		Prorated Operating Expenses												
68		Administrative & General												
69	920	Administrative & General		704,514										
70	921	Office Supplies & Expenses		126,931										
71	922	Admin. Expenses Transferred												
72	923	Outside Services Employed		193,224										
73	924	Property Insurance												
74	925	Injuries & Damages												
75	926	Employee Pensions & Benefits												
76	927	Franchise Requirements												
77	928	Regulatory Commission Exp.												
78	929	Duplicate Charges		(66,650)										
79	930.1	General Advertising		12,194										
80	930.2	Misc.		164,077										
81	931	Rents		6,383										
82	935	Maint. of General Plant		114,945										
83		Accounts 920-935		1,255,619										
84		Power Supply	EX6-PS											
85		Transmission	EX6-TR											
86		Distribution	EX6-D	1,255,619	579,726	35,706	99,325	405,287	14,219	49,019	8,246	15,508	5,080	265
87		Subtotal - A&G		1,255,619	579,726	35,706	99,325	405,287	14,219	49,019	8,246	15,508	5,080	265

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

Line No.	Acct. No.	Description	Class. Factor	Total	Residential (04-RS)	Residential W/Space Heat (04-RS)	GS Small (04-GSS)	GS Large (04-GSL)	GS Large W/Space Heat (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Temp Service (04-CS)
88	408	Other Taxes												
89		Power Supply	EX6-PS											
90		Transmission	EX6-TR											
91		Distribution	REV	1,054,289	472,556	22,282	51,921	372,384	11,480	47,155	4,871	18,155	6,465	345
92		Subtotal - Other Taxes		1,054,289	472,556	22,282	51,921	372,384	11,480	47,155	4,871	18,155	6,465	345
93	421-	Miscellaneous Expense												
94	426,431	Power Supply	EX6-PS											
95		Transmission	EX6-TR											
96		Distribution	EX6-D	325,399	150,238	9,253	25,740	105,032	3,685	12,703	2,137	4,019	1,316	69
97		Subtotal - Misc. Expense		325,399	150,238	9,253	25,740	105,032	3,685	12,703	2,137	4,019	1,316	69
98		Fixed Charges												
99	403-	Depreciation												
100	407	Power Supply	PROPLNT											
101		Transmission	TRNPLNT	449,053	168,530	11,133	21,723	196,453	6,906	25,509	2,488	7,232	2,354	106
102		Distribution	DSTPLNT	1,286,213	521,722	34,058	104,569	453,731	16,226	52,601	10,366	19,043	7,613	262
103		Subtotal - Depreciation		1,735,265	690,252	45,191	126,292	650,185	23,132	78,110	12,854	26,275	9,966	368
104	408	Property Taxes												
105		Power Supply	REV											
106		Transmission	REV											
107		Distribution	REV											
108		Subtotal - Property Taxes												
109														
110		Total Oper. Expenses		31,592,084	12,744,847	819,816	1,785,396	12,551,537	478,455	1,702,686	185,725	505,380	158,843	6,057
111														
112	427	Interest-LT												
113		Power Supply	PROPLNT											
114		Transmission	TRNPLNT											
115		Distribution	DSTPLNT	4,069,354	1,650,639	107,752	330,838	1,435,528	51,337	166,419	32,796	60,248	24,086	830
116		Subtotal - Interest-LT		4,069,354	1,650,639	107,752	330,838	1,435,528	51,337	166,419	32,796	60,248	24,086	830
117		Required Margin												
118		Power Supply	PROPLNT											
119		Transmission	TRNPLNT											
120		Distribution	DSTPLNT	3,652,155	1,481,412	96,705	296,919	1,288,354	46,074	149,357	29,434	54,071	21,616	745
121		Subtotal - Required Margin		3,652,155	1,481,412	96,705	296,919	1,288,354	46,074	149,357	29,434	54,071	21,616	745
122		Summary of Revenue Requirements												
123		Power Supply		21,395,934	8,201,386	543,365	1,035,164	9,086,483	358,139	1,280,249	119,821	367,776	111,907	3,769
124		Transmission		900,579	337,988	22,328	43,566	393,989	13,850	51,159	4,989	14,504	4,720	212
125		Distribution		17,017,079	7,337,524	458,580	1,334,423	5,794,946	203,877	687,054	123,145	237,418	87,919	3,650
126		Total Rev. Req.		39,313,592	15,876,898	1,024,273	2,413,153	15,275,419	575,867	2,018,462	247,955	619,698	204,545	7,631

Rate Class Weighting Factors

I. Three Phase Vs. Single Phase Class Weighting Factors

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

	<u>1Ø</u>	<u>3Ø</u>
1. kWh Meter	\$90	\$286
2. kWh & kW Meter	\$275	\$500
3. kWh & kW Meter (PF/KVAR)	\$286	\$705
4. Service ¹	\$247	\$409
5. Transformer ²	\$1,718	\$2,751
6. Primary Line ³	\$714	\$1,252

B. Weighting Factors for Relative 3Ø Class Investment Costs

1. Meter (3Ø Interval Recording)	\$1,200 ÷	\$90 =	13.33
2. Meter (3Ø w/demand, PF/KVAR)	\$705 ÷	\$90 =	7.83
3. Meter (3Ø w/demand)	\$500 ÷	\$90 =	5.56
4. Meter (3Ø w/o demand)	\$286 ÷	\$90 =	3.18
5. Meter (1Ø w/demand)	\$275 ÷	\$90 =	3.06
6. Service	\$409 ÷	\$247 =	1.65
7. Transformer	\$2,751 ÷	\$1,718 =	1.60
8. Primary Line	\$1,252 ÷	\$714 =	1.75

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

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

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

Estimate of Class Demands Summary

Description	Total System	Residential			GS Large		Industrial (04-IS)	Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Temp Service (04-CS)
		Residential (04-RS)	W/Space Heat (04-RS)	GS Small (04-GSS)	GS Large (04-GSL)	W/Space Heat (04-Rider 1)					
<u>Class Billing Determinants</u>											
Number of Consumers	21,388	12,240	685	2,564	1,260	43	8	147	70	23	3
Energy (MWh)	310,617	120,802	8,021	14,999	128,481	5,525	19,297	1,751	5,596	1,619	40
Billing Demand (kW)	560,029	-	-	-	488,576	14,694	56,760	-	-	-	-
<u>Estimated Demand Responsibility</u>											
Non-Coincident Consumer Demand	242,216	134,950	9,588	14,933	62,909	2,591	5,355	1,780	4,213	2,757	50
Non-Coincident Class Demand	80,065	29,336	1,931	3,878	36,275	1,105	4,270	438	1,190	421	24
Coincident Class Demand - Avc. Monthly	55,711	20,500	1,349	2,710	25,349	772	2,984	306	831	294	17
Coincident Class Demand - Summer											
Coincident Class Demand - Winter											
Coincident Class Demand - Weighted	55,711	20,500	1,349	2,710	25,349	772	2,984	306	831	294	17
Coincident Class Demand - Transm.									60.2		

Estimate of Class Demands

Line No.	Description	Total System	Residential			GS Large		Industrial (04-IS)	Municipal Power (04-M-1)	Water Pumping (04-WP)	Irrigation (04-IP-1)	Temp Service (04-CS)	Lighting (PAL-SL-1, PAL-L, SL-
			Residential (04-RS)	W/Space Heat (04-RS)	GS Small (04-GSS)	GS Large (04-GSL)	W/Space Heat (04-Rider 1)						
1	Non-Coincidental Class Demand - Average Monthly												
2	Total System Sales (MWh)	310,617	120,802	8,021	14,999	128,481	5,525	19,297	1,751	5,596	1,619	40	4,488
3	Line Losses	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%
4	kWh Purchased (MWh)	333,032	129,519	8,600	16,081	137,752	5,923	20,689	1,877	6,000	1,735	43	4,812
5	Divide by Hours	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760
6	Average Demand (kWh)	38,017	14,785	982	1,836	15,725	676	2,362	214	685	198	5	549
7													
8	Average Customers	21,489	12,240	685	2,564	1,260	43	8	147	70	23	3	4,446
9													
10	Calculated Maximum Demand ¹	68,485	29,336	1,931	3,878	23,989	1,183	4,676	438	1,190	421	24	1,418
11													
12	Substitutions												
13	Bary Curve Estimate (Max. Annual or Seas.) ²		n/a	n/a	n/a	36,275	1,105	4,270	n/a	n/a	n/a	n/a	n/a
14	Other Substitutions ³		n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	1,195
15	Non-Coincident Class Demand	80,065	29,336	1,931	3,878	36,275	1,105	4,270	438	1,190	421	24	1,195
16	Sum of Non-Coincidental Demands of Individual Customers - Annual Peak												
17	Peak Month Sales Data												
18	Peak Month		Aug-10	Jan-10	Jan-10	Oct-10	Jan-10	Jan-10	Aug-10	Aug-10	Aug-10	May-10	Dec-10
19	kWh Sales		16,668,481	1,122,372	1,714,642	12,646,628	660,678	1,882,201	209,581	639,621	557,649	13,136	402,197
20	Consumers		12,363	636	2,616	1,248	46	8	140	70	27	5	164
21	Sum of Individual Consumer's Non-coincident Demands		134,951	9,584	14,931	82,797	3,847	8,501	1,778	4,197	2,797	60	83,235
22													
23	Substitute (from Historical Billing Records)		n/a	n/a	n/a	60,513	2,591	5,355	n/a	n/a	n/a	n/a	n/a
24	Non-Coincident Demand from Billing Records		n/a	n/a	n/a	469,963	14,694	56,760	n/a	n/a	n/a	n/a	n/a
25	Sum of Individual Customer Non-Coincident Peak Demands (Adjusted to Test Year) ⁴		134,950	9,588	14,933	62,909	2,591	5,355	1,780	4,213	2,757	50	3,091

¹ The class diversified demand is calculated based on the formulas contained in RUS Demand Tables (Bulletin 45-2). The formula is as follows:
Class Diversified Demand = $L8 \times (1 - 0.4 \times L8 + 0.4 \times (L8^2 + 40)^{0.5}) \times (0.005925 \times (L4 \times 1,000 + (L8 \times 12)^{0.885}))$

² See "Annual Bary Curve Estimates"

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

⁴ The sum of the Individual Consumers Non-coincident Demands is calculated using the RUS demand for a single customer multiplied by the Test Year number of customers.
Sum of Individual Consumer Demands = $(1 - 0.4 \times 1 + 0.4 \times (1^2 + 40)^{0.5}) \times (0.005925 \times (L19 + L20)^{0.885})$

⁵ Adjusted to Test Year conditions.

Estimate of Class Demands

Line No.	Description	Total System	Residential (04-RS)	Residential W/Space Heat (04-RS)	GS Small (04-GSS)	GS Large (04-GSL)	GS Large W/Space Heat (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-1)	Water Pumping (04-WP)	Irrigation (04-IP-1)	Temp Service (04-CS)	Lighting (PAL-SL-1, PAL-I, SL-
26	Annual Bary Curve Estimates												
27	Sum of Monthly Non-Coincidental Demands for Test Year		-	-	-	488,576	14,694	56,760	-	-	-	-	-
28													
29	MWh Sales		-	-	-	128,481	5,525	19,297	-	-	-	-	-
30													
31	Load Factor (730 hours per month)					36.0%	51.5%	46.6%					
32													
33	Coincidence Factor (From Bary Curve)		n/a	n/a	n/a	83.1%	84.2%	84.2%	n/a	n/a	n/a	n/a	n/a
34													
35	Billing Months per Year		12	12	12	12	12	12	12	12	12	3	12
36													
37	Estimated Non-Coincidental Average Monthly Demand ((L2*L8)/L10)		n/a	n/a	n/a	33,834	1,031	3,983	n/a	n/a	n/a	n/a	n/a
38	Estimated Non-Coincidental Demand - Average Monthly (Including Line Loss)		n/a	n/a	n/a	36,275	1,105	4,270	n/a	n/a	n/a	n/a	n/a
39													
40	Determination of Class Coincident Demand - Average Monthly												
41	System Coincident Demand - Average Monthly (Per Exhibit II)	55,711											
42													
43	Coincidence Factors from Other Sources ¹		n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	50.00%
44	Average Monthly Non-Coincident Demand ²		-	-	-	-	-	-	-	-	-	-	1,195
45	Coincident Demand - Direct Assigned	598	-	-	-	-	-	-	-	-	-	-	598
46													
47	Remaining Coincident Demand	55,113											
48	Remaining Non-Coincident Demand	78,870	29,336	1,931	3,878	36,275	1,105	4,270	438	1,190	421	24	-
49	Coincidence Factor for Remaining Classes ¹	69.9%	69.9%	69.9%	69.9%	69.9%	69.9%	69.9%	69.9%	69.9%	69.9%	69.9%	
50	Coincident Demand for Remaining Classes		20,500	1,349	2,710	25,349	772	2,984	306	831	294	17	-
51	Coincident Demand - Ave. Monthly	55,711	20,500	1,349	2,710	25,349	772	2,984	306	831	294	17	598

Outdoor Lighting

A. Separately Metered Energy

kWh	56,142
Ave. LF	<u>49%</u>
	<u>13</u>
	<u>13</u>

Private Area / Street Lighting

A. Unmetered Lights

Size/Type	# of Lights	Power Required Per Light			Estimated Annual kWh/month	Estimated kWh	Total kW 1
		Lamp kW	Ballast kW	Total kW			
100 W MV	-	0.100	0.035	0.135	45	-	0.0
175 W MV	2,068	0.175	0.035	0.210	75	1,861,200	434.3
250 W MV	138	0.250	0.050	0.300	107	177,192	41.4
400 W MV	259	0.400	0.050	0.450	173	537,684	116.6
50 W HPS	-	0.050	0.020	0.070	25	-	0.0
70 W HPS	-	0.070	0.025	0.095	34	-	0.0
100 W HPS	1,537	0.100	0.035	0.135	45	829,980	207.5
150 W HPS	386	0.150	0.050	0.200	68	314,976	77.2
200 W HPS	243	0.200	0.055	0.255	87	253,692	62.0
250 W HPS		0.250	0.060	0.310	108	-	0.0
400 W HPS	403	0.400	0.075	0.475	173	836,628	191.4
1000 W HPS	59	1.000	0.100	1.100	394	278,952	64.9
Total	5,093					<u>5,090,304</u>	<u>1,195</u>
Average monthly usage						<u>83.29</u>	<u>0.235</u>

Development of Allocation Factors – BUNDLED

Line No.	Description	Units	Total	Residential (04-RS)	Residential W/Space Heat (04-RS)	GS Small (04-GSS)	GS Large (04-GSL)	GS Large W/Space Heat (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Temp Service (04-CS)
1	Allocation Factor Input Data												
2	Energy												
3	Energy Sales -- All	MWh	310,617	120,802	8,021	14,999	128,481	5,525	19,297	1,751	5,596	1,619	40
4	Energy Sales -- On-Peak	MWh											
5	Energy Sales -- Off-Peak	MWh											
6	Dist. Losses	MWh	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%	7.22%
7	Energy -- All @ Sub.	MWh	333,032	129,519	8,600	16,081	137,752	5,923	20,689	1,877	6,000	1,735	43
8	Energy -- On-Peak @ Sub.	MWh											
9	Energy -- Off-Peak @ Sub.	MWh											
10	Trans. Losses	MWh											
11	Energy -- All @ Source	MWh	333,032	129,519	8,600	16,081	137,752	5,923	20,689	1,877	6,000	1,735	43
12	Energy -- On-Peak @ Source	MWh											
13	Energy -- Off-Peak @ Source	MWh											
14	Demand												
15	Non-Coinc. Demand @ Cons.	kW	242,216	134,950	9,588	14,933	62,909	2,591	5,355	1,780	4,213	2,757	50
16	Class Non-Coinc. Demand @ Sub.	kW	80,065	29,336	1,931	3,878	36,275	1,105	4,270	438	1,190	421	24
17	Class Non-Coinc. Demand Transm.	kW											
18	Summer Coinc. Demand	kW											
19	Winter Coinc. Demand	kW											
20	Other Coinc. Demand	kW											
21	Coinc. Demand @ Sub.	kW	55,711	20,500	1,349	2,710	25,349	772	2,984	306	831	294	17
22	Coinc. Demand @ Source	kW	55,711	20,500	1,349	2,710	25,349	772	2,984	306	831	294	17
23	Average and Excess Demand												
24	Average Demand	kW	38,017	14,785	982	1,836	15,725	676	2,362	214	685	198	5
25	Class Excess Demand	kW	42,047	14,551	949	2,042	20,550	429	1,908	224	505	223	19
26	Allocated Excess Demand	kW	17,694	6,123	399	859	8,648	181	803	94	212	94	8
27	Avg. & Excess Demand	kW	55,711	20,908	1,381	2,695	24,373	857	3,165	309	897	292	13
28	Margin												
29	Present Rate Margin	\$	10,886,452	4,879,554	230,080	536,127	3,845,188	118,536	486,912	50,302	187,462	66,761	3,561
30	Proposed Rate Revenue	\$	33,182,966	13,418,928	795,774	1,614,857	13,325,660	490,525	1,818,321	175,112	569,742	183,388	7,542
31	Consumer												
32	No. Consumers		21,489	12,240	685	2,564	1,260	43	8	147	70	23	3
33	Pri. Line Weight. Factor			1.00	1.00	1.16	1.52	1.52	1.75	1.00	1.00	1.75	1.00
34	Weight. No. of Cons.		18,230.4	12,240.0	685.0	2,968.4	1,909.1	65.2	14.0	147.0	70.0	39.8	3.0
35	Transf. Weight. Factor			1.00	1.00	1.13	1.41	1.41	1.60	1.00	1.00	1.60	1.00
36	Weight. No. of Cons.		18,006.9	12,240.0	685.0	2,886.1	1,777.1	60.6	12.8	147.0	70.0	36.3	3.0
37	Service Weight. Factor			1.00	1.00	1.14	1.45	1.45	1.65	1.00	1.00	1.65	1.00
38	Weight. No. of Cons.		18,082.2	12,240.0	685.0	2,913.8	1,821.6	62.2	13.2	147.0	70.0	37.5	3.0
39	Meter Weight. Factor			1.00	1.00	3.58	4.76	4.76	7.83	5.56	5.56	7.83	1.00
40	Weight. No. of Cons.		29,841.2	12,240.0	685.0	9,173.8	6,000.0	204.8	62.7	816.7	388.9	177.6	3.0
41	Cons. Acct. Weight Factor			1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
42	Weight. No. of Cons.		17,131.6	12,240.0	685.0	2,564.0	1,260.0	43.0	8.0	147.0	70.0	22.7	3.0

Development of Allocation Factors – BUNDLED
(Continued)

Line No.	Description	Data Line		Total	Residential (04-RS)	Residential W/Space Heat (04-RS)	GS Small (04-GSS)	GS Large (04-GSL)	GS Large W/Space Heat (04-Rider 1)	Industrial (04-IS)	Municipal Power (04-M-I)	Water Pumping (04-WP)	Irrigation (04-IP-I)	Temp Service (04-CS)
		No.	Name											
43	Allocation Factors													
44	Energy Related													
45	Energy -- All @ Sub.	7	E1	1.000000	0.388908	0.025824	0.048287	0.413630	0.017786	0.062124	0.005637	0.018016	0.005211	0.000129
46	Energy -- On-Peak @ Sub.	8	E2											
47	Energy -- Off-Peak @ Sub.	9	E3											
48	Energy -- All @ Source	11	E4	1.000000	0.388908	0.025824	0.048287	0.413630	0.017786	0.062124	0.005637	0.018016	0.005211	0.000129
49	Energy -- On-Peak @ Source	12	E5											
50	Energy -- Off-Peak @ Source	13	E6											
51														
52	Demand Related													
53	Non-coinc. Demand @ Cons.	15	D1	1.000000	0.557148	0.039583	0.061651	0.259725	0.010695	0.022110	0.007349	0.017393	0.011381	0.000205
54	Non-coinc. Demand @ Class	16	D2	1.000000	0.366408	0.024119	0.048433	0.453075	0.013806	0.053333	0.005476	0.014857	0.005261	0.000305
55	Non-coinc. Demand @ Transm	17	D3											
56	Summer Coinc. Demand	18	D4											
57	Winter Coinc. Demand	19	D5											
58	Other Coinc. Demand	20	D6											
59	Coinc. Demand @ Sub.	21	D7	1.000000	0.367970	0.024222	0.048640	0.455007	0.013865	0.053560	0.005500	0.014920	0.005283	0.000306
60	Coinc. Demand @ Source	22	D8	1.000000	0.367970	0.024222	0.048640	0.455007	0.013865	0.053560	0.005500	0.014920	0.005283	0.000306
61	Avg. & Excess	27	D9	1.000000	0.375301	0.024793	0.048375	0.437484	0.015379	0.056807	0.005540	0.016105	0.005241	0.000235
62	Avg. & Excess (w/o Enbridge)	28	D10	1.000000	0.375301	0.024793	0.048375	0.437484	0.015379	0.056807	0.005540	0.016105	0.005241	0.000235
63														
64	Revenue Related													
64	Present Rate Margin	29	R1	1.000000	0.448223	0.021135	0.049247	0.353209	0.010888	0.044726	0.004621	0.017220	0.006133	0.000327
65	Proposed Rate Revenue	30	R2	1.000000	0.404392	0.023981	0.048665	0.401581	0.014782	0.054797	0.005277	0.017170	0.005527	0.000227
66														
67	Consumer Related													
68	No. of Cons.	32	C1	1.000000	0.569603	0.031877	0.119319	0.058636	0.002001	0.000372	0.006841	0.003258	0.001055	0.000140
69	Pri. Line Weight. Cons.	34	C2	1.000000	0.671407	0.037575	0.162826	0.104722	0.003574	0.000770	0.008063	0.003840	0.002182	0.000165
70	Transf. Weight. Cons.	36	C3	1.000000	0.679740	0.038041	0.160279	0.098689	0.003368	0.000711	0.008164	0.003887	0.002016	0.000167
71	Services Weight. Cons.	38	C4	1.000000	0.676910	0.037883	0.161144	0.100738	0.003438	0.000731	0.008130	0.003871	0.002072	0.000166
72	Meter Weight. Cons.	40	C5	1.000000	0.410171	0.022955	0.307421	0.201063	0.006862	0.002100	0.027367	0.013032	0.005950	0.000101
73	Cons. Acct. Weight. Cons.	42	C6	1.000000	0.714470	0.039985	0.149665	0.073548	0.002510	0.000467	0.008581	0.004086	0.001323	0.000175

RJM-15 - LAC Cost of Service

Southern Pioneer Electric Company, Inc.
MKEC Area Local Access Charge
Revenue Requirements

Test Year January 1, 2010 to December 31, 2010
Adjusted for Known and Measurable Changes

<u>Line</u>	<u>Description</u>	<u>Source</u>	<u>Total</u>		<u>Allocation Factor</u>		<u>Allocated to LAC</u>	<u>Percent of Total</u>
			<u>MKEC Area</u>	<u>Name</u>	<u>Factor</u>			
1	<u>Operating Expenses</u>							
2	Transmission O&M	Ex. (RJM-SP-2), pg. 1	\$ 720,789		1.000000	\$ 720,789	20.98%	
3	Distribution O&M	Ex. (RJM-SP-2), pg. 1	4,022,272	DOM	0.000000	-	0.00%	
4	Administration & General	Ex. (RJM-SP-2), pg. 1	1,335,637	LAB	0.016711	22,320	0.65%	
5	Depreciation							
6	Transmission	pg 3	348,574		1.000000	348,574	10.15%	
7	Distribution (LAC Only)	pg 3	-		1.000000	-	0.00%	
8	General Plant	pg 3	461,604	LAB	0.016711	7,714	0.22%	
9	Taxes	Ex. (RJM-SP-2), pg. 1	-	NP	0.239407	-	0.00%	
10	Other Deductions	Ex. (RJM-SP-2), pg. 1	353,372	NP	0.239407	84,600	2.46%	
11	Subtotal Operating Expense	Sum(L2:L9)				\$ 1,183,997		
12								
13	Net DSC Margin Requirements	Ex. (RJM-SP-3), pg. 1	7,515,677	NP	0.239407	\$ 1,799,303		
14	L.T. Interest		4,547,758	NP	0.239407	\$ 1,088,764	31.69%	
15	Margin					\$ 710,540	20.68%	
16								
17	Income Tax Requirement @ 63.620%	Ex. (RJM-SP-3), pg. 2				452,045	13.16%	
18								
19	<u>Total Revenue Requirements</u>	L11 + L13 + L17				\$ 3,435,346	100.00%	
20								
21	<u>Billing Demand</u>	pg. 5				1,061,430 kW		
22	<u>Reference Workpaper</u>	L19 / L21				\$ 3.24 /kW/mo		
22								

Southern Pioneer Electric Company, Inc.
MKEC Area Local Access Charge
Allocation Factors

Test Year January 1, 2010 to December 31, 2010
Adjusted for Known and Measurable Changes

<u>Line No.</u>	<u>Description</u>	<u>Source</u>		
1	Distribution O&M Allocation Factor			
2	Distribution Plant used in LAC		\$	-
3	Total Distribution Plant	General Ledger	\$	37,156,169
4				
5	Allocation Factor	L2 / L3	DOM	-
6				
7	Labor Allocation Factor			
8	Transmission	General Ledger	\$	31,146
9	Distribution Wages			
10	Total Distribution Wages	General Ledger	\$	1,303,037
11	Allocation Factor	L5	DOM	-
12	Dist Wages Allocated to LAC	L10 * L11	\$	-
13	Total LAC Wages	L8 + L12	\$	31,146
14				
15	Total Wages	General Ledger	\$	1,938,805
16	Less: Administration & General Wages	General Ledger		75,063
17	Wages Other than A&G	L15 - L16	\$	1,863,742
18				
19	Labor Allocator	L13 / L17	LAB	0.016711
20				
21	Reference Workpaper			
22	Plant-in-Service			
23	Transmission	General Ledger	\$	15,251,790
24	Distribution Used in LAC			-
25	Subtotal	L23 + L24	\$	15,251,790
26	Allocated General Plant			
27	Total General Plant	General Ledger	\$	5,852,844
28	Allocation Factor	L19	LAB	0.016711
29	Allocated General Plant	L27 * L28	\$	97,809
30	Total LAC Plant-in-Service	L25 - L16	\$	15,349,599
31				
32	Accumulated Reserves for Depreciation			
33	Transmission	General Ledger	\$	7,295,911
34	Distribution Used in LAC			-
35	Subtotal	L33 + L34	\$	7,295,911
36	Allocated General Plant			
37	Total General Plant	General Ledger	\$	1,393,984
38	Allocation Factor	L19	LAB	0.016711
39	Allocated General Plant	L37 * L38	\$	23,295
40	Total LAC Accum. Depr. Res.	L35 + L39	\$	7,319,207
41	Net Plant Used in LAC	L30 - L40	\$	8,030,393
42				
43	Total Plant in Service	General Ledger	\$	58,260,803
44	Total Accum. Reserves for Depr.	General Ledger		24,717,910
45	Total Net Plant	L43 - L44	\$	33,542,893
46				
47	Net Plant Allocator	L41 / L45	NP	0.239407

¹ The amount of distribution facilities utilized in providing local access service was determined through a direct assessment by MKEC.

Southern Pioneer Electric Company, Inc.
MKEC Area Local Access Charge
Depreciation Expense

Test Year January 1, 2010 to December 31, 2010
Adjusted for Known and Measurable Changes

<u>Line</u>	<u>Description</u>	<u>Source</u>	<u>Plant In Service As of 12/31/10</u>	<u>Depr. Rate</u>	<u>Depr. Expense</u>
1	Facilities Used in Providing LAC Service				
2	Transmission Facilities				
3	350 Land and Land Rights	General Ledger	\$ 100,229	-	\$ -
4	352 Structures and Improvements	General Ledger	277,092	0.02110	5,847
5	353 Station Equipment	General Ledger	5,565,767	0.01830	101,854
6	355 Poles and Fixtures	General Ledger	4,638,767	0.03300	153,079
7	356 O.H. Conductors and Devices	General Ledger	4,669,935	0.01880	87,795
8	358 U.G. Conductors and Devices	General Ledger	-	0.02390	-
9	Subtotal	Sum(L3:L8)	<u>\$ 15,251,790</u>		<u>\$ 348,574</u>
10	Distribution Facilities				
11	360 Land and Land Rights	General Ledger	\$ -	-	-
12	361 Structures and Improvements	General Ledger	-	0.01730	-
13	362 Station Equipment	General Ledger	-	0.01100	-
14	Subtotal	Sum(L11:L13)	<u>\$ -</u>		<u>\$ -</u>
15	Total	L9 + L14	<u>\$ 15,251,790</u>		<u>\$ 348,574</u>
16					
17			<u>As of 12/31/10</u>		
18	General Plant				
19	389 Land and Land Rights	General Ledger	\$ 140,161	-	\$ -
20	390 Structures and Improvements	General Ledger	1,677,028	0.031600	52,994
21	391 Office Furniture and Equipment	General Ledger	389,975	0.133633	52,114
22	392 Transportation Equipment	General Ledger	2,807,946	0.115600	324,599
23	393 Stores Equipment	General Ledger	212,624	0.047500	10,100
24	394 Tools, Shop and Garage Equip	General Ledger	22,193	0.046500	1,032
25	395 Laboratory Equipment	General Ledger	173,952	0.049800	8,663
26	396 Power Operated Equipment	General Ledger	-	0.069700	-
27	Communication Equipment	General Ledger	387,539	0.023300	9,030
28	Miscellaneous Equipment	General Ledger	41,426	0.074200	3,074
29	Total	Sum(L19:L28)	<u>\$ 5,852,844</u>	0.078868	<u>\$ 461,604</u>
30					
31	Plant in Service as of 12/31/10	General Ledger	\$ 5,852,844	0.078868	\$ 461,604

Southern Pioneer Electric Company, Inc.
MKEC Area Local Access Charge
Credit for Third Party Revenue

Test Year January 1, 2010 to December 31, 2010
Adjusted for Known and Measurable Changes

<u>Line</u>	<u>Description</u>	<u>Source</u>	<u>Alloc. Factor</u>	<u>Amount</u>
1	Total Revenue Credit			
2	Third Party Billing Demand	pg. 5		396,089 kW
3	LAC Rate	pg. 1		\$ 3.24 /kW/mo
4	LAC Third Party Revenue	Mult(L2:L3)		\$ 1,283,329
5				
6	Allocation of Revenue Credit to Categories			
7	Transmission O&M	pg. 1	20.98%	\$ 269,262
8	Distribution O&M	pg. 1	0.00%	-
9	Administration & General	pg. 1	0.65%	8,338
10	Depreciation	pg. 1	10.37%	133,097
11	Property Taxes	pg. 1	0.00%	-
12	Other Deductions	pg. 1	2.46%	31,604
13	L.T. Interest	pg. 1	31.69%	406,725
14	Margin Requirements	pg. 1	20.68%	265,434
15	Income Taxes	pg. 1	13.16%	168,869
16	Total	Sum(L7:L15)	100.00%	\$ 1,283,329

Reference Workpaper

**Southern Pioneer Electric Company
Summary of Proposed Local Access Billing Demands (kW) – 2010**

<u>Line</u>	<u>Description</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	<u>Oct</u>	<u>Nov</u>	<u>Dec</u>	<u>Total</u>
1	Total Local Access System ¹	82,317	77,973	70,204	69,464	85,465	114,174	118,581	115,342	111,227	79,676	79,237	74,137	1,077,798
2	CP Date	07	08	24	07	29	22	14	02	15	07	29	01	
3	CP Time (hour Ending)	2000	2000	2000	1100	1700	1600	1600	1600	1600	1600	1900	2100	
4														
5	Wholesale Customers @ Del. Pt.													
6	Ashland (KMEA)--Metered	1,980	1,917	1,647	1,729	2,155	3,357	3,638	3,740	3,267	2,095	1,693	1,772	28,989
7	Ashland (KMEA)--Generation	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Subtotal--Ashland	1,980	1,917	1,647	1,729	2,155	3,357	3,638	3,740	3,267	2,095	1,693	1,772	28,989
9	Kingman (KPP)	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	72,000
10	Kingman (KPP) Generation	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Subtotal--Kingman	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	72,000
12	Greensburg	2,729	2,374	1,698	1,651	1,704	2,373	2,518	2,432	2,108	1,593	1,847	1,709	24,736
13	Greensburg Wind Farm ²	10,408	10,787	10,718	11,845	8,498	9,325	7,776	4,880	9,253	3,608	11,741	10,583	109,421
14	Isabel (AR)	314	293	252	281	243	296	247	269	321	305	273	272	3,367
15	KEPCO	14,047	13,006	10,703	10,414	13,637	14,391	13,600	15,409	16,789	14,040	11,122	10,416	157,576
16	Subtotal--Wholesale	35,478	34,376	31,017	31,920	32,237	35,743	33,779	32,730	37,738	27,642	32,675	30,753	396,089
17	Losses @ 1.86% of 34.5 kV Output	355	327	266	262	330	380	372	406	418	335	278	264	3,993
18	Subtotal with Losses (@ Source)	35,833	34,704	31,283	32,182	32,567	36,123	34,152	33,136	38,156	27,977	32,952	31,016	400,082
19														
20	Southern Pioneer Retail													
21	Retail with Losses (@ Source)	46,484	43,270	38,920	37,282	52,897	78,051	84,429	82,206	73,071	51,699	46,285	43,121	677,716
22	Losses @ 1.83% of 34.5 kV Input	849	790	711	681	966	1,425	1,542	1,501	1,334	944	845	787	12,375
23	Retail @ Delivery Point	45,635	42,480	38,209	36,601	51,931	76,626	82,888	80,705	71,737	50,755	45,439	42,333	665,340

¹ Reference Workpaper

² January and February CP is 2011 as customer was not online during these months in 2010.

**RJM-16 - Proposed Rate Tariffs,
Schedule LAC**

THE STATE CORPORATION COMMISSION OF KANSAS

Index No. 24

MID-KANSAS ELECTRIC COMPANY, LLC
(Name of Issuing Utility)

Schedule: 11-LAC

Original Schedule Sheet 1

SOUTHERN PIONEER DIVISION
(Territory to which schedule is applicable)

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 1 of 2 Sheets

LOCAL ACCESS DELIVERY SERVICE

AVAILABLE

Entire Service Area.

APPLICABLE

For delivery to wholesale (sales for resale) customers over MKEC's 34.5 kV (or other available lower primary voltage) subtransmission/distribution system.

CHARACTER OF SERVICE

Alternating current, 60 cycle, three phase, 34.5 kV or other available lower primary voltage.

MONTHLY RATE

Demand Charge @ \$3.24 per kW.

MONTHLY BILLING DEMAND

When service is provided in association with network service, the Monthly Billing Demand shall be defined as the Customer's kilowatt contribution to the maximum hourly demand coincident with Southern Pioneer's monthly Local Access Delivery System peak in the billing month, as measured at the low side of the delivery point. For other local access service (including, but not limited to, point-to-point transmission service requiring local access service and service reservations), Monthly Billing Demand shall be the greater of the Customer's service request or actual maximum monthly demand.

LOSSES

Real Power Losses are associated with all Local Access Delivery service. The Local Access Delivery customer is responsible for replacing losses associated with all transmission service as calculated by MKEC or paying MKEC for the Real Power Losses at MKEC's wholesale rate. The applicable Real Power Loss factor for the entire service area is as follows:

LOSS FACTORS

1.86 percent of energy as measured at delivery point.

DELAYED PAYMENT

As per schedule DPC.

Issued _____
Month Day Year

Effective _____
Month Day Year

By _____
Signature Title

THE STATE CORPORATION COMMISSION OF KANSAS

Index No. 24

MID-KANSAS ELECTRIC COMPANY, LLC
(Name of Issuing Utility)

Schedule: 11-LAC

Original Schedule _____ Sheet 2

SOUTHERN PIONEER DIVISION

(Territory to which schedule is applicable)
No supplement or separate understanding
shall modify the tariff as shown hereon.

Sheet 2 of 2 Sheets

TERMS AND CONDITIONS

Service will be rendered under Company's Rules and Regulations as filed with the Kansas Corporation Commission.

Issued _____
Month Day Year

Effective _____
Month Day Year

By _____
Signature Title

**RJM-17 - Kansas Expedited
Access Charge Filing**

Appendix I

Expedited Access Charge Filing

An expedited access charge filing procedure will be implemented effective January 1, 1991, or as soon as all local exchange company access tariffs from this proceeding become effective. The following represents an explanation of the procedure and filing requirements.

General Description:

This expedited procedure is available to all local exchange companies except Southwestern Bell Telephone Company and the United companies. This filing is intended to address revisions to intrastate Carrier Common Line (CCL) access rates only, through the review and adjustment of intrastate IntraLATA/interLATA revenue requirements of individual local exchange companies. This expedited filing process will not be used to make or propose changes in basic local exchange rates, or rates other than access. Filings must be made on behalf of individual local exchange telephone companies and not by multiple or aggregated telephone companies. Failure to file or make application in the prescribed format will result in denial of the application and thus the 120-day time frame is not initiated

unless a filing is in compliance with the prescribed format.

Applications will not be held open or continue to be carried on the Commission's calendar subject to a company "completing" or "updating" its filing to comply with the prescribed format.

Filing Requirements:

- 1) The Commission must receive written notice of the intent to file an application at least 30 days in advance of the filing.
- 2) The Commission will make a determination on the filing within 120 days from the application filing date. Interexchange carriers passing on changes in access rates to end users may elect to aggregate these rate changes for an annual period and revise applicable tariffs January 1 of each year, subject to existing Commission oversight.
- 3) There is no restriction on dates by which applications can be submitted to the Commission.
- 4) Existing statutes or filing requirements guiding the procedures to be used in making application with the Commission are not altered or waived by this procedure.

Filing Format:

- 1) The company must file using the formats attached which support the company's revenue requirements by jurisdiction, the residual CCL calculation format and the summary revenue requirement format. The total of all jurisdictional components should be reconciled to the actual book amounts by explaining any differences or adjustments between the filing and the company's books. The residual CCL calculation format should provide a reconciliation, where applicable, between components of annualized revenues (current volumes x rates) and actual book amounts by explaining any differences or adjustments.
- 2) The filing should incorporate the most recent actual twelve months data and should not include projected or forecasted rate base or expense components in the revenue requirements.
- 3) Only the intrastate intraLATA/interLATA jurisdictional revenue requirements are subject to review or revision in this proceeding.
- 4) The overall rate of return to be used in the expedited filing for the duration of the plan will be the company's specific Commission authorized rate of return, if applicable, or 10.00 percent, absent evidence supporting an alternative rate of return.

5) Weighted DEM is capped at 85.00 percent to toll.

6) Adjustments and level of review.

a) The intent is that the filing not incorporate or include rate case type adjustments by the filing company, nor focus on proposed rate case type adjustments by intervenors or staff. Proposed issues or adjustments should focus on compliance issues such as, but not limited to, Part 32, 36, 64, Generally Accepted Accounting Principles (GAAP) and Kansas Commission orders. Rate case type adjustments may be avoidable to the extent that applications are based on a test period representative of historical or prospective revenue requirements without any extraordinary or unusual costs. The intent is that the expedited process not be abused by the filing of an application that takes advantage of a nonrecurring or extraordinary circumstance which does not represent a reasonable revenue requirement.

b) The filing may at the company's discretion include rate case type adjustments. However, for the expedited filing to be considered complete and in compliance with filing requirements all adjustments must be separately identified,

include supporting calculations and workpapers, include a narrative explanation of each adjustment and provide the total adjustment multiplied by the specific separations factor to arrive at the jurisdictional adjustment by account number.

Generally, it can probably be expected that company filed rate case adjustments will prompt proposed rate case adjustments by intervenors and staff.

The attached forms are to be used by the applicants in expedited access charge filings.

TELEPHONE COMPANY _____

TWELVE MONTHS ENDING _____

REVENUE REQUIREMENT SUMMARY

ATTACHMENT I

REFERENCE	TOTAL COMPANY AS ADJUSTED	INTERSTATE				INTRASTATE				TAX	EAS	EXCHANGE
		MESSAGE		PRIVATE LINE		MESSAGE		PRIVATE LINE				
		INTRA	INTER	INTRA	INTER	INTRA	INTER	INTRA	INTER			
1	NET RATE BASE	11A, Ln20										
2	RATE OF RETURN											
3	RETURN	Ln1*Ln2										
4	FEDERAL INCOME TAXES	(See Note Below)										
5	STATE INCOME TAXES	(See Note Below)										
6	OPERATING EXPENSES AND TAXES	11B, Ln28										
7	NONOPERATING EXPENSES	11B, Ln30										
8	UNCOLLECTIBLES	11B, Ln 34										
9	TOTAL EXPENSES	Ln4, Ln8										
10	REVENUE REQUIREMENT	Ln3, Ln8										

Note - Attach schedule showing income tax calculation and reconciliation to book amounts

TELEPHONE COMPANY _____
 TWELVE MONTHS ENDING _____

NET PLANT INVESTMENT

ATTACHMENT II-A

ALLOCATION FACTORS	ACCOUNT NUMBER	TOTAL COMPANY PER BOOKS	ADJUSTMENTS (DETAIL REQUIRED)	TOTAL COMPANY AS ADJUSTED	INTERSTATE				INTRASTATE				TAX	PAS	EQUIPMENT	
					MESSAGE		PRIVATE LINE		MESSAGE		PRIVATE LINE					
					INTBA	INTER	INTBA	INTER	INTBA	INTER	INTBA	INTER				
TELEPHONE PLANT IN SERVICE																
4	GENERAL SUPPORT FACILITIES	2110														
5	CENTRAL OFFICE SWITCHING EQUIP	2210														
6	OPERATOR SYSTEMS EQUIPMENT	2220														
7	CENTRAL OFFICE TRANS EQUIP	2230														
8	INFORMATION CR/O/T/TERM EQUIP	2310														
9	CABLE AND WIRE FACILITIES	2410														
10	TANGIBLE ASSETS	2600														
11	INTANGIBLE ASSETS	2690														
12	TOTAL PLANT IN SVC A/C 2001															
LESS:																
13	ACCUM DEPREG - PLANT IN SVC	3100														
14	NET PLANT INVESTMENT															
LESS:																
15	ACCUM AMORT - TANGIBLE PROP	3400														
16	DEFERRED INCOME TAXES	XXXX														
17	OTHER DEFERRED CREDITS - NET	4370														
ADD:																
18	MATERIALS AND SUPPLIES	1220														
19	RTB STOCK	XXXX														
20	NET RATE BASE															
21	PERCENT DISTRIBUTION															

Note - 'XXXX' indicates various accounts should be included as appropriate.

TELEPHONE COMPANY _____
 TWELVE MONTHS ENDING _____

EXPENSES AND TAXES

ATTACHMENT II-B

ALLOCATION FACTORS	ACCOUNT NUMBER	TOTAL COMPANY PER BOOKS	ADJUSTS (DETAIL REQUIRED)	TOTAL COMPANY AS ADJUSTED	INTERSTATE				INTRASTATE				TWX	EAS	EXCHANGE	
					MESSAGE		PRIVATE LINE		MESSAGE		PRIVATE LINE					
					INTBA	INTER	INTBA	INTER	INTBA	INTER	INTBA	INTER				
1	GENERAL SUPPORT ASSETS															
2	TELEPHONE PLANT IN SERVICE															
3	COE, ROT & CAWF															
4	NET TELEPHONE PLANT, M&S															
5	BIG THREE EXPENSES															
OPERATING EXPENSE AND TAX																
6	NETWORK SUPPORT EXPENSE	6110														
7	GENERAL SUPPORT EXPENSE	6120														
8	CENTRAL OFFICE EXPENSE	6210														
9	INFORMATION DRUG/TERM EXPENSE	6300														
10	CABLE AND WIRE FACILITIES EXP	6400														
11	PLANT SPECIFIC OPER EXP															
12	OTHER PLANT EXPENSE	6510														
13	NETWORK OPERATIONS EXPENSE	6530														
14	ACCESS CHARGE EXPENSE	6540														
15	DEPRECIATION AND AMORT	6580														
16	PLANT NON-SPEC OPER EXP															
17	MARKETING EXPENSE	6610														
18	SERVICES EXPENSE	6620														
19	CUSTOMER OPERATIONS EXP															
20	EXECUTIVE AND PLANNING EXP	6710														
21	GENERAL AND ADMIN EXPENSE	6720														
22	CORPORATE OPERATIONS EXP															
23	SUBTOTAL OPERATING EXPENSES															
24	OTHER OPERATING TAX	7210														
25	EQUAL ACCESS EXPENSE															
26	TOTAL OPERATING EXPENSE AND TAX															
27	PERCENT DISTRIBUTION															
NON OPERATING EXPENSES																
28	CONTRIBUTIONS (NOTE A)	7370														
29	OTHER NON OPER EXP (NOTE B)	7370														
30	TOTAL NON OPERATING EXPENSE															
UNCOLLECTIBLES																
31	END USER M&S TOLLS	5310														
32	END USER COMMON LINE	5320														
33	IX CARRIER	5330														
34	TOTAL UNCOLLECTIBLES															

NOTE A - Include one-half of contributions above-the-line.
 NOTE B - Subject to review depending on appropriateness.

TELEPHONE COMPANY _____
 TWELVE MONTHS ENDING _____

CCL RESIDUAL RATE DEVELOPMENT

ATTACHMENT III

INTERLATA					
(A)	(B)	(C)	(D)	(E)	(F)
	ANNUAL UNITS	CURRENT TARIFFED RATES	ANNUALIZED REVENUES (B)(C)	ACTUAL BOOKED REVENUES	DIFFERENCE (See Note A Below) (D)-(E)
1 LOCAL SWITCHING					
LOCAL TRANSPORT					
2 A. TERMINATION					
3 B. FACILITY	XXXXXX	XXXXXX	XXXXXX		XXXXXX
4 INFORMATION SURCHARGE					
5 BILLING & COLLECTION	XXXXXX	XXXXXX	XXXXXX		XXXXXX
6 SPECIAL	XXXXXX	XXXXXX	XXXXXX		XXXXXX
7 FG&B REVENUE					
8 OTHER ACCESS REVENUES					
9 NET ACCESS REVS (w/o CCL)					\$

INTRALATA					
(G)	(H)	(I)	(J)	(K)	(L)
	ANNUAL UNITS	CURRENT TARIFFED RATES	ANNUALIZED REVENUES (B)(C)	ACTUAL BOOKED REVENUES	DIFFERENCE (See Note A Below) (J)-(K)
1 LOCAL SWITCHING					
LOCAL TRANSPORT					
2 A. TERMINATION					
3 B. FACILITY	XXXXXX	XXXXXX	XXXXXX		XXXXXX
4 INFORMATION SURCHARGE					
5 BILLING & COLLECTION	XXXXXX	XXXXXX	XXXXXX		XXXXXX
6 PRIVATE LINE (Special Access)	XXXXXX	XXXXXX	XXXXXX		XXXXXX
7 OTHER ACCESS REVENUES					
8 NET ACCESS REVS (w/o CCL)					\$

RESIDUAL CCL RATE DETERMINATION

	INTERLATA		INTRALATA		TOTAL
	REFERENCE	AMT/QT	REFERENCE	AMT/QT	
10 ACCESS REV FROM	Att I, Ln 10	\$	Att I, Ln 10	\$	\$
11 Less: NET ACCESS REVS (w/o CCL)	Col E, Ln 9	\$	Col K, Ln 8	\$	\$
12 Less: REVENUE SHFT	Note B	\$	Note B	\$	\$
13 CCL RESIDUAL REVENUE FROM	Ln 10-11-12	\$	Ln 10-11-12	\$	\$
14 JURISD. CCL MOU	Input		Input		
15 CCL RATE MINUTE					\$

Note A - All differences in Column F and L must be identified and explained.
 Note B - All historical levels previously approved by the Commission, not updated for current access lines.
 'xxxxxx' indicates columns do not have to be completed for this line item.

**RJM-18 - Kentucky Statute,
Regulation, and Pass-Through
Example**

**278.455 Reduction of operating expenses by G&T or distribution cooperative --
Effect on rates -- Authority for administrative regulations.**

- (1) Notwithstanding any other statute to the contrary, a G&T or distribution cooperative may at any time decrease regulated operating revenues by an amount to be determined solely by the cooperative utility. If the revenue reduction is allocated among and within the consumer classes on a proportional basis that will result in no change in the rate design currently in effect, the revised rates and tariffs shall be authorized and made permanent on the proposed effective date.
- (2) Notwithstanding any other statute, any revenue increase authorized by the Public Service Commission or any revenue decrease authorized in subsection (1) of this section that is to flow through the effects of an increase or decrease in wholesale rates may, at the distribution cooperative's discretion, be allocated to each class and within each tariff on a proportional basis that will result in no change in the rate design currently in effect. In the event of an increase in the wholesale rates and tariffs of the wholesale supplier by the Public Service Commission, the rates and tariffs of the distribution cooperative that have been revised on a proportional basis to result in no change in the rate design shall be authorized and shall become effective on the same date as those of the wholesale supplier. In those cases where an interim increase in the power supplier's wholesale rates is authorized, the distribution cooperative's flow through rates shall be interim. The distribution cooperative's permanent rates and tariffs shall become effective on the date that the wholesale supplier's permanent rates become effective as ordered by the commission.
- (3) Any rate increase or decrease as provided for in subsections (1) and (2) of this section shall not apply to special contracts under which the rates are subject to change or adjustment only as stipulated in the contract.
- (4) The Public Service Commission shall promulgate administrative regulations pursuant to KRS Chapter 13A to establish filing requirements and notice requirements to the commission, the Attorney General, and the public under this section.

Effective: July 15, 1998

History: Created 1998 Ky. Acts ch. 188, sec. 2, effective July 15, 1998.

807 KAR 5:007. Filing and notice requirements for a generation and transmission cooperative or a distribution cooperative to decrease rates or for a distribution cooperative to change rates to reflect a change in the rates of its wholesale supplier. Exhibit B.M.18
2 of 27

RELATES TO: KRS 278.180, 278.455

STATUTORY AUTHORITY: KRS 278.040(3), 278.180(1), 278.455(4)

NECESSITY, FUNCTION, AND CONFORMITY: KRS 278.040(3) provides that the commission may promulgate administrative regulations to implement the provisions of KRS Chapter 278. KRS 278.180(1) provides that, except upon application of a utility for a lesser time, a change shall not be made in a rate except upon thirty (30) days' notice to the commission, stating plainly the changes proposed to be made and the time when the changed rates shall go into effect. KRS 278.455(1) provides that a generation and transmission cooperative or a distribution cooperative may decrease regulated operating revenues if the decrease is allocated proportionately among customer classes so that a change will not result to the rate design currently in effect. KRS 278.455(2) provides that a distribution cooperative may change its rates to reflect a change in the rate of its wholesale supplier if the effects of an increase or decrease are allocated to each class and within each tariff on a proportional basis that will result in no change in the rate design currently in effect. KRS 278.455(4) requires the commission to promulgate administrative regulations establishing filing requirements and notice requirements to the commission, the Attorney General, and the public for rate changes made pursuant to KRS 278.455. This administrative regulation prescribes filing and notice requirements for a generation and transmission cooperative or a distribution cooperative to decrease rates and for a distribution cooperative to change rates to reflect a change in the rates of its wholesale supplier.

Section 1. Filing Requirements. To decrease rates, a generation and transmission cooperative or a distribution cooperative shall file with the commission an original and five (5) copies, and with the Attorney General's Office of Rate Intervention one (1) copy, of the following information:

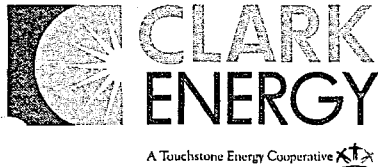
- (1) The tariff incorporating the reduced rates, specifying an effective date no sooner than thirty (30) days from the date filed;
- (2) The name and address of the filing cooperative;
- (3) A brief statement of the facts demonstrating that the filing is made pursuant to the authority of KRS 278.455;
- (4) A comparison of the current and proposed rates;
- (5) An analysis demonstrating that:
 - (a) The rate change does not change the rate design currently in effect; and
 - (b) The revenue change has been allocated to each class and within each tariff on a proportional basis;
- (6) A certification that a complete copy of the materials filed with the commission has been sent to the Attorney General's Office of Rate Intervention;
- (7) A statement that notice of the rate change pursuant to Section 3 of this administrative regulation has been given, not more than thirty (30) days prior to the date the application is filed, by one (1) of the following methods:
 - (a) By typewritten notice mailed to all customers;
 - (b) By publication in a newspaper of general circulation in the affected area; or
 - (c) By publication in a periodical distributed to all members of the cooperative; and
 - (8) A copy of the notice given pursuant to subsection (7) of this section.

Section 2. To change rates to reflect an increase or decrease in its wholesale supplier's rates, a distribution cooperative shall file with the commission an original and five (5) copies, and with the Attorney General's Office of Rate Intervention one (1) copy, of the following information:

- (1) The tariff incorporating the new rates and specifying an effective date no sooner than the effective date of the wholesale supplier's rate change; and
- (2) The information required by Section 1(2) through (8) of this administrative regulation.

Section 3. Contents of Notice. Notice given pursuant to Section 1(7) of this administrative regulation shall include the following information:

- (1) The name, address, and phone number of the cooperative;
- (2) The existing rates and the revised rates for each customer class;
- (3) The effect of the rate change, stated both in dollars and as a percentage, upon the average bill for each customer class;
- (4) A statement, as appropriate, that:
 - (a) The rate reduction is being made at the sole discretion of the utility, pursuant to KRS 278.455(1); or
 - (b) The rates are being revised to reflect a change in wholesale rates pursuant to KRS 278.455(2); and
- (5) A statement that a person may examine the rate application at the main office of the utility or at the office of the Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky. (25 Ky.R. 2989; Am. 26 Ky.R. 385; eff. 8-20-99.)



May 27, 2010

Mr. Jeff Derouen
Executive Director
Public Service Commission
211 Sower Boulevard
Frankfort, KY 40602

RECEIVED
MAY 27 2010
PUBLIC SERVICE
COMMISSION

Re: Clark Energy Cooperative, Inc. Pass-Through of East Kentucky Power Cooperative, Inc. Wholesale Rate Adjustment- PSC Case No. 2010-00170.

Dear Mr. Derouen:

Please find enclosed for filing with the Commission an original and 5 copies of Clark Energy Cooperative, Inc. Filing for Pass-Through of East Kentucky Power Cooperative, Inc. ("EKPC") Wholesale Rate Adjustment in Case No. 2010-00167. This filing includes the following information as required by 807 KAR 5:007:

1. The full name and filing address of the filing cooperative is: [807 KAR 5:007, Sections 1(2) and 2(2)]

Clark Energy Cooperative, Inc.
PO Box 748
Winchester, KY 40392

2. Clark Energy Cooperative, Inc. Proposed Tariffs reflecting the new rates specifying an effective date of July 1, 2010, the effective date of EKPC's wholesale rate change are attached as Exhibit 1. [807 KAR 5:007, Section 2(1)]
3. This filing is pursuant to the provisions of KRS 278.455(2). [807 KAR 5:007, Sections 1(3) and 2(2)]
4. A comparison of the current and proposed rates of Clark Energy Cooperative, Inc. is attached as Exhibit 2. [807 KAR 5:007, Sections 1(4) and 2(2)]


Mr. Jeff Derouen
May 27, 2010
Page 2

5. Attached as Exhibit 3 is a billing analysis which shows the existing and proposed rates for each rate class. Clark Energy Cooperative, Inc. hereby states that the effects of the increase in rates from its wholesale supplier, EKPC, are being passed through to its retail tariffs on a proportional basis and that the rate design structure proposed for each retail rate schedule does not change the rate design currently in effect. [807 KAR 5:007, Sections 1(5)(a), 1(5)(b), and 2(2)]
6. A certification that one complete copy of this filing has been filed with the Office of Rate Intervention, Office of the Attorney General, is attached as Exhibit 4. [807 KAR 5:007, Sections 1(6) and 2(2)]
7. Notice of the proposed rate change has been given, not more than thirty (30) days prior to May 27, 2010, by publication in a newspaper of general circulation in the affected area of Clark Energy Cooperative, Inc. A copy of this notice is attached as Exhibit 5. [807 KAR 5:007, Sections 1(7)(b), 1(8), and 2(2)]
8. The notice attached as Exhibit 5 contains the required information pursuant to 807 KAR 5:007, Section 3.

Clark Energy Cooperative, Inc. hereby requests that the Commission accept this filing and allow the pass-through to its retail rates of the wholesale rate adjustment granted to EKPC as of the effective date of such adjustment.

Respectfully submitted,

Clark Energy Cooperative, Inc.



Robert L. Rose
Attorney Representing Coop

For All Areas Served
Community, Town or City

P.S.C. No. 2

4th Revision SHEET NO. 43

CANCELLING P.S.C. NO. 2

3rd Revision SHEET NO. 43

Clark Energy Cooperative Inc.
Name of Issuing Corporation

CLASSIFICATION OF SERVICE

Schedule R: Residential

AVAILABILITY

Available to all residential consumers subject to established rules and regulations of the Distributor.

CHARACTER OF SERVICE

Single phase, 60 Hertz, at available secondary voltages.

DELIVERY POINT

The delivery point at which the secondary or utilization voltage is provided shall be specified by the Distributor.

RATES

\$12.50	Facility Charge	(I)
\$0.099734	per kWh for all energy	(I)

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be \$12.50. (I)

FUEL ADJUSTMENT CHARGE

The above rate may be increased or decreased by an amount per kWh equal to the fuel adjustment amount per kWh as billed by the Wholesale Power Supplier plus an allowance for line losses. The allowance for line losses will not exceed 10% and is based on a twelve month moving average of such losses.

DATE OF ISSUE: May 27, 2010 DATE EFFECTIVE: Service rendered on and after July 1, 2010

ISSUED BY: _____ TITLE : PRESIDENT & C.E.O.
Name of Officer

Issued by authority of an Order of the Public Service Commission in Case No. 2010-00170, dated _____.

For All Areas Served
Community, Town or City

P.S.C. No. 2

4th Revision SHEET NO. 45

CANCELLING P.S.C. NO. 2

3rd Revision SHEET NO. 45

Clark Energy Cooperative Inc.
Name of Issuing Corporation

CLASSIFICATION OF SERVICE

Schedule D: Time of-Use Marketing Service

AVAILABILITY

Available to all Rate "R" consumers for separately metered off peak requirements subject to the established time of use restrictions. Applicable to programs approved by the Kentucky PSC as a part of EKPC wholesale marketing rates.

CHARACTER OF SERVICE

Single phase, 60 Hertz, at available secondary voltages.

DELIVERY POINT

The delivery point at which the secondary or utilization voltage is provided shall be specified by the Distributor.

TIME OF DAY RESTRICTIONS

MONTH	OFF PEAK HOURS
October thru April	10:00 P.M. To 7:00 A.M., EST
	12:00 Noon to 5:00 P.M., EST
May thru September	10:00 P.M. thru 10:00 A.M., EST

RATES

\$0.06757 per kWh for all energy

(1)

DATE OF ISSUE: May 27, 2010

DATE EFFECTIVE: Service rendered on and after July 1, 2010

ISSUED BY _____ TITLE PRESIDENT & C.E.O.
Name of Officer

Issued by authority of an Order of the Public Service Commission in Case No. 2010-00170 dated _____.

For All Areas Served
Community, Town or City

P.S.C. No. 2

4th Revision SHEET NO. 47

Clark Energy Cooperative Inc.
Name of Issuing Corporation

CANCELLING P.S.C. NO. 2

3rd Revision SHEET NO. 47

CLASSIFICATION OF SERVICE

Schedule T: Outdoor lighting Facilities

AVAILABILITY

Available for general outdoor lighting facilities.

RATES

Lamp Rating	Annual Rate Per Lamp	Average Annual Energy Use Per Lamp	Average Monthly Energy Use Per Lamp
400 Watt	\$18.82 per mo	1,848 kWh	154 kWh

(I)

CONDITIONS OF SERVICE

Rates applicable only to lamps and associated appurtenances. Other facilities required may be provided subject to the Distributor's established contract policies and practices.

TERMS OF PAYMENT

The above charges are net and payable within ten days from the date of the bill.

FUEL ADJUSTMENT CHARGES

The above rate may be increased or decreased by an amount per kWh equal to the fuel adjustment amount per kWh as billed by the Wholesale Power Supplier plus an allowance for line losses. The

DATE OF ISSUE: May 27, 2010

DATE EFFECTIVE: Service rendered on and after July 1, 2010

ISSUED BY _____ TITLE PRESIDENT & C.E.O.
Name of Officer

Issued by authority of an Order of the Public Service Commission in
Case No. 2010-00170 dated _____.

For All Areas Served
Community, Town or City

P.S.C. No. 2

4th Revision SHEET NO. 49

Clark Energy Cooperative Inc.
Name of Issuing Corporation

CANCELLING P.S.C. NO. 2

3rd Revision SHEET NO. 49

CLASSIFICATION OF SERVICE

Schedule S: Outdoor Lighting Facilities

AVAILABILITY

Available for general outdoor lighting facilities.

RATES

<u>Lamp Rating</u>	<u>Monthly Rate Per Lamp</u>	<u>Average Annual Energy Use Per Lamp</u>	<u>Average Monthly Energy Use Per Lamp</u>
175 Watt	\$10.15 per mo	840 kWh	70 kWh

(I)

CONDITIONS OF SERVICE

1. Rate applicable only to lamps and associated appurtenances. Other facilities required may be provided subject to the Distributor's established policies and practices.
2. The Consumer shall execute an agreement for service under this schedule for a period of not less than one year.

FUEL ADJUSTMENT CHARGE

The above rates may be increased or decreased by an amount per kWh equal of the fuel adjustment amount per kWh as billed by the Wholesale Power Supplier plus an allowance for line losses. The allowance for line losses will not exceed 10% and is based on a twelve month moving average of such losses.

DATE OF ISSUE: May 27, 2010 DATE EFFECTIVE: Service rendered on and after July 1, 2010

ISSUED BY _____ TITLE PRESIDENT & C.E.O.
Name of Officer

Issued by authority of an Order of the Public Service Commission in Case No. 2010-00170 dated _____.

For All Areas Served
Community, Town or City

P.S.C. No. 2

4th Revision SHEET NO. 51

CANCELLING P.S.C. NO. 2

3rd Revision SHEET NO. 51

Clark Energy Cooperative Inc.
Name of Issuing Corporation

CLASSIFICATION OF SERVICE

Schedule E: Public Facilities

AVAILABILITY

Available to public facilities with Kilowatt (kW) demands less than 50 kW subject to established rules and regulations of the Distributor. Not applicable to outdoor lighting system requirements.

CHARACTER OF SERVICE

Single phase, 60 Hertz, at available secondary voltages.

DELIVERY POINT

The delivery point at which the secondary or utilization voltage is provided shall be specified by the Distributor.

RATES

\$ 16.66	Facility Charge	(I)
\$ 0.10672	All kWh	(I)

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be \$ 16.66. (I)

FUEL ADJUSTMENT CHARGE

The above rate may be increased or decreased by an amount per kWh equal to the fuel adjustment amount per kWh as billed by the Wholesale Power Supplier plus an allowance for line losses. The

DATE OF ISSUE: May 27, 2010 DATE EFFECTIVE: Service rendered on and after July 1, 2010

ISSUED BY _____ TITLE PRESIDENT & C.E.O.
Name of Officer

Issued by authority of an Order of the Public Service Commission in Case No. 2010-00170 dated _____.

For All Areas Served
Community, Town or City

P.S.C. No. 2

4th Revision SHEET NO. 53

Clark Energy Cooperative Inc.
Name of Issuing Corporation

CANCELLING P.S.C. NO. 2

3rd Revision SHEET NO. 53

CLASSIFICATION OF SERVICE

Schedule C: General Power Service

AVAILABILITY

Available for all non-residential general power requirements with Kilowatt (kW) demands less than 50 kW subject to established rules and regulations of the Distributor.

CHARACTER OF SERVICE

Single or three phase, 60 Hertz, at available secondary voltages.

DELIVERY POINT

The delivery point at which the secondary or utilization voltage is provided shall be specified by the Distributor.

RATES

\$25.47	Facility Charge-Single Phase	(I)
\$50.42	Facility Charge-Three Phase	(I)
\$0.10620	Per kWh for all energy	(I)

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be \$25.47 single phase and \$50.42 (I)
for three phase service.

DATE OF ISSUE: May 27, 2010 DATE EFFECTIVE: Service rendered on and after July 1, 2010

ISSUED BY _____ TITLE PRESIDENT & C.E.O.
Name of Officer

Issued by authority of an Order of the Public Service Commission in
Case No. 2010-00170 dated _____.

For All Areas Served
Community, Town or City

P.S.C. No. 2

4th Revision SHEET NO. 56

Clark Energy Cooperative Inc.
Name of Issuing Corporation

CANCELLING P.S.C. NO. 2

3rd Revision SHEET NO. 56

CLASSIFICATION OF SERVICE

Schedule L: General Power Service

AVAILABILITY

Available to all commercial and industrial consumers for general power requirements with Kilowatt (kW) demands of 50 kW or greater but less than 500 kW.

CONDITIONS OF SERVICE

A power contract shall be executed by the consumer for service under this rate schedule. The power contract shall specify a contract demand for minimum billing purposes of 50 kW or greater but less than 500 kW.

CHARACTER OF SERVICE

Limited to single or three phase, 60 Hertz, at a secondary delivery voltage of 480 volts or less.

DELIVERY POINT

The delivery point shall be specified within the power contract.

RATES

\$64.18	Facility Charge	(I)
\$ 6.51	per kW of billing demand	(I)
\$ 0.07851	per kWh for all energy	(I)

DATE OF ISSUE: May 27, 2010 DATE EFFECTIVE: Service rendered on and after July 1, 2010

ISSUED BY _____ TITLE PRESIDENT & C.E.O.

Name of Officer

Issued by authority of an Order of the Public Service Commission in Case No. 2010-00170 dated _____.

For All Areas Served
Community, Town or City

P.S.C. No. 2

4th Revision SHEET NO. 59

CANCELLING P.S.C. NO. 2

3rd Revision SHEET NO. 59

Clark Energy Cooperative Inc.
Name of Issuing Corporation

CLASSIFICATION OF SERVICE

Schedule P: General Power Service

AVAILABILITY

Available to all commercial and industrial consumers for general power requirements with Kilowatt (kW) demands of 500 kW or greater.

CONDITIONS OF SERVICE

A power contract shall be executed by the consumer for service under this rate schedule. The power contract shall specify a contract demand for minimum billing purposes of 500 kW or greater.

CHARACTER OF SERVICES

Limited to three phase, 60 Hertz, at a secondary of delivery voltage specified within the power contract.

DELIVERY POINT

The delivery point shall be specified within the power contract.

RATES

\$87.38	Facility Charge	(I)
\$ 6.25	per kW of billing demand	(I)
\$ 0.06829	per kWh for all energy	(I)

DATE OF ISSUE: May 27, 2010 **DATE EFFECTIVE:** Service rendered on and after July 1, 2010

ISSUED BY _____ **TITLE** PRESIDENT & C.E.O.

Name of Officer

Issued by authority of an Order of the Public Service Commission in Case No. 2010-00170 dated _____.

For All Areas Served
Community, Town or City

P.S.C. No. 2

4th Revision SHEET NO. 62

Clark Energy Cooperative Inc.
Name of Issuing Corporation

CANCELLING P.S.C. NO. 2

3rd Revision SHEET NO. 62

CLASSIFICATION OF SERVICE

Schedule M: General Power Service

AVAILABILITY

Available to all commercial and industrial consumers for general power requirements at primary delivery voltage with Kilowatt (kW) demands of 1,000 kW or greater but less than 5,000 kW.

CONDITIONS OF SERVICE

A power contract shall be executed by the consumer for service under this rate schedule. The power contract shall specify a contract demand for minimum billing purposes of 1,000 or greater but less than 5,000 kW.

CHARACTER OF SERVICE

Three phase, 60 Hertz, at a delivery voltage specified within the power contract.

DELIVERY POINT

The delivery point shall be specified within the power contract.

RATES

Demand Charge:	\$10.13	per kW of billing demand	(I)
Energy Charge:	\$0.07171	per kWh for all energy	(I)

DATE OF ISSUE: May 27, 2010 DATE EFFECTIVE: Service rendered on and after July 1, 2010

ISSUED BY _____ TITLE PRESIDENT & C.E.O.
Name of Officer

Issued by authority of an Order of the Public Service Commission in Case No. 2010-00170 dated _____.

EXHIBIT 2
Page 1 of 1

The present and proposed rates structures of Clark Energy Cooperative, Inc. are listed below:

<u>Rate Class</u>	<u>Present</u>	<u>Proposed</u>
Sch R: Residential		
Facility Charge per month	\$12.00	\$12.50
Energy charge per kWh	\$0.095773	\$0.099734
Sch D: Time of Use Marketing		
Per kWh for all energy	\$0.06489	\$0.06757
Sch T: Outdoor Lighting Facilities (per month)		
400 watt	\$18.07	\$18.82
Sch S: Outdoor Lighting Facilities (per month)		
175 watt	\$9.75	\$10.15
Sch E: Public Facilities		
Facility Charge per month	\$16.00	\$16.66
Energy charge per kWh	\$0.10248	\$0.10672
Sch C: General Power Service Single Phase		
Facility Charge per Month	\$24.46	\$25.47
Per kWh for all Energy	\$0.10198	\$0.10620
Sch C: General Power Service Three Phase		
Facility Charge per Month	\$48.42	\$50.42
Per kWh for All Energy	\$0.10198	\$0.10620
Sch L: General Power Service		
Facility charge per Month	\$61.63	\$64.18
Demand charge per kW	\$6.25	\$6.51
Energy charge per kWh	\$0.07539	\$0.07851
Sch P: General Power Service		
Facility charge per Month	\$83.91	\$87.38
Demand charge per kW	\$6.00	\$6.25
Energy charge per kWh	\$0.06558	\$0.06829
Sch M: General Power Service		
Demand charge per kW	\$9.73	\$10.13
Energy charge per kWh	\$0.06886	\$0.07171

Clark Energy

Billing Analysis

for the 12 month ending December 31, 2009

	Present Total Base Revenues	% of Total Revenues	Proposed Total Base Revenues	% of Total Revenues	\$ Increase	% Increase
Schedule "R"	\$ 34,674,549	73.92%	\$ 36,109,716	73.92%	\$ 1,435,167	4.14%
Schedule "D"	122,538	0.26%	127,599	0.26%	5,061	4.13%
Schedule T	160,841	0.34%	167,517	0.34%	6,676	4.15%
Schedule "S"	1,056,335	2.25%	1,099,671	2.25%	43,337	4.10%
Schedule "E"	481,005	1.03%	500,899	1.03%	19,894	4.14%
Schedule "C": Single Phase	1,958,360	4.17%	2,039,361	4.17%	81,001	4.14%
Schedule "C-3": Three-Phase	1,516,932	3.23%	1,579,696	3.23%	62,764	4.14%
Schedule "L"	5,315,985	11.33%	5,536,245	11.33%	220,260	4.14%
Schedule "P"	851,962	1.82%	887,269	1.82%	35,307	4.14%
Schedule "M"	770,550	1.64%	802,393	1.64%	31,843	4.13%
Totals	\$ 46,909,057	100.00%	\$ 48,850,367	100.00%	\$ 1,941,311	4.14%
Total FAC Component	1,013,785		1,013,785			
Total ESc Component	2,461,676		2,461,676			
Total Green Power	957		957			
Total Incl. Surcharges	\$ 50,385,475		\$ 52,326,785		\$ 1,941,311	3.85%

Clark Energy's Portion of EKPC's Wholesale Rate Increase \$ 1,940,310
Over (Under) Recovery due to Rounding \$ 1,001

Note: In order to appropriately match retail rates to the forecasted test year used for wholesale rates, an escalation factor was applied to each member system's 2009 actual billing determinants. The escalation factors used in this proceeding were an outcome of preliminary load forecast projections.

Clark Energy
Billing Analysis
for the 12 months ended December 30, 2009

Clark Schedule "R"										
2009 Billing Determinants	Escalation %	Escalated Billing Determinants. (3)=(1)*(2)	Present		Actual Comp % of Base Rates	Proposed		Dollar Increase (7)	Percent Increase (8)	Proposed Comp.% of Base Rates
			Rate (4)	Revenues (5)=((4)*(3)		Rate (6)	Revenues (7)=(6)*(3)			
(1)	(2)	(3)=(1)*(2)	(4)	(5)=((4)*(3)		(6)	(7)=(6)*(3)	(7)	(8)	
Customer Charge	290,649	1.31%	294,457	\$ 12.00	\$ 3,533,478	10.19%	\$ 12.50	\$ 3,680,706	\$ 147,228	10.19%
Energy Charge per kWh	310,292,026	4.79%	325,155,014	\$ 0.095773	31,141,071	89.81%	\$ 0.099734	32,429,010.2	1,287,939	89.81%
Billing Adjustments					-			-	-	
Total from Base Rates					34,674,549	100.00%		36,109,716.4	1,435,167	4.14%
Plus Fuel Adjustment					793,918			793,918.0	-	
Plus Environmental Surcharge					1,843,623			1,843,623.0	-	
Green Power					957			957.0	-	
Total Revenues					\$ 37,313,047			\$ 38,748,214	\$ 1,435,167	\$ 1,435,167
Average					\$ 126.72			\$ 131.59	\$ 4.87	
Percent										3.85%

Clark Schedule "D"										
2009 Billing Determinants	Escalation %	Escalated Billing Determinants. (3)=(1)*(2)	Present		Actual Comp % of Base Rates	Proposed		Dollar Increase (7)	Percent Increase (8)	Proposed Comp.% of Base Rates
			Rate (4)	Revenues (5)=((4)*(3)		Rate (6)	Revenues (7)=(6)*(3)			
(1)	(2)	(3)=(1)*(2)	(4)	(5)=((4)*(3)		(6)	(7)=(6)*(3)	(7)	(8)	
Number of Bills	2,840	1.31%	2,877	\$ -	-		\$ -	\$ -	\$ -	
Energy	1,802,075	4.79%	1,888,394	\$ 0.06489	122,538	100.00%	\$ 0.06757	127,599	5,061	100.00%
Billing Adjustments					-			-	-	
Rev from Bases Rates					122,538	100.00%		127,599	5,061	4.13%
FUEL					6,685			6,685	-	
ESC					57			57	-	
TOTAL REVENUE					\$ 129,280			\$ 134,341	\$ 5,061	3.91%
Average					\$ 44.93			\$ 46.69	\$ 1.76	
Percent										3.91%

Clark Energy
Billing Analysis
for the 12 months ended December 30, 2009

Clark Schedule T	2009 Billing Determinants (1)	Escalation % (2)	Escalated Billing Determinants. (3)=(1)*(2)	Present		Actual Comp % of Base Rates	Proposed		Dollar Increase (7)	Percent Increase (8)	Proposed Comp.% of Base Rates
				Rate (4)	Revenues (5)=((4)*(3)		Rate (6)	Revenues (7)=(6)*(3)			
200 WATT	-	0.00%	-	\$ -	\$ -		\$ -	\$ -	-		
300 WATT	-	0.00%	-	-	-		-	-	-		
400 WATT	8,901	0.00%	8,901	\$ 18.07	160,841	100.00%	\$ 18.82	167,517	6,676	100.00%	
Billing Adjustments					-			-	-		
Rev from Bases Rates					160,841	100.00%		167,517	6,676	4.15%	
FUEL					2,752			2,752	-		
ESC					3,143			3,143	-		
TOTAL REVENUE					\$ 166,736			173,412	6,676		
Average					\$ 18.73		\$ 19.48	\$ 0.75			
Percent										4.00%	

Clark Schedule "S"	2009 Billing Determinants (1)	Escalation % (2)	Escalated Billing Determinants. (3)=(1)*(2)	Present		Actual Comp % of Base Rates	Proposed		Dollar Increase (7)	Percent Increase (8)	Proposed Comp.% of Base Rates
				Rate (4)	Revenues (5)=((4)*(3)		Rate (6)	Revenues (7)=(6)*(3)			
Customer Charge (Lamp Charge)	108,342	0.00%	108,342	\$ 9.75	\$ 1,056,335	100.00%	\$ 10.15	\$ 1,099,671	\$ 43,337		
Energy Charge per kWh	7,576,576	0.00%	7,576,576	-	-		\$ -	-	-		
Billing Adjustments					-			-	-		
Total from Base Rates					1,056,335	100.00%		1,099,671	43,337	4.10%	
Plus Fuel Adjustment					15,199			15,199	-		
Plus Environmental Surcharge					3,057			3,057	-		
Total Revenues					\$ 1,074,591			\$ 1,117,927	\$ 43,337		
Average					\$ 9.92		\$ 10.32	\$ 0.40			
Percent										4.03%	

Clark Schedule "E"	2009 Billing Determinants (1)	Escalation % (2)	Escalated Billing Determinants. (3)=(1)*(2)	Present		Actual Comp % of Base Rates	Proposed		Dollar Increase (7)	Percent Increase (8)	Proposed Comp.% of Base Rates
				Rate (4)	Revenues (5)=((4)*(3)		Rate (6)	Revenues (7)=(6)*(3)			
Customer Charge	3,527	0.00%	3,527	\$ 16.00	\$ 56,432	11.73%	\$ 16.66	\$ 58,760	\$ 2,328		
Energy Charge per kWh	3,845,709	7.73%	4,142,982	\$ 0.10248	424,573	88.27%	\$ 0.10672	442,139	17,566	88.27%	
Billing Adjustments					-			-	-		
Total from Base Rates					481,005	100.00%		500,899	19,894	4.14%	
Plus Fuel Adjustment					9,452			9,452	-		
Plus Environmental Surcharge					25,802			25,802	-		
Total Revenues					\$ 516,259			\$ 536,153	\$ 19,894	3.85%	
Average					\$ 146.37		\$ 152.01	\$ 5.64			
Percent											

Clark Energy
Billing Analysis
for the 12 months ended December 30, 2009

Clark Schedule "C": Single Phase											
2009 Billing Determinants	Escalation %	Escalated Billing Determinants. (3)=(1)*(2)	Present		Actual Comp % of Base Rates	Proposed		Dollar Increase (7)	Percent Increase (8)	Proposed Comp.% of Base Rates	
			Rate (4)	Revenues (5)=(4)*(3)		Rate (6)	Revenues (7)=(6)*(3)				
			(1)	(2)		(3)	(4)				(5)
Customer Charge	16,742	1.27%	16,955	\$ 24.46	\$ 414,710	21.18%	\$ 25.47	\$ 431,834	\$ 17,124	21.17%	
Energy Charge per kWh	14,050,673	7.73%	15,136,790	\$ 0.10198	1,543,650	78.82%	\$ 0.10620	1,607,527	63,877	78.83%	
Billing Adjustments					-			-			
Total from Base Rates					1,958,360	100.00%		2,039,361	81,001	4.14%	
Plus Fuel Adjustment					32,605			32,605	-		
Plus Environmental Surcharge					195,122			195,122	-		
Total Revenues					\$ 2,186,087			\$ 2,267,088	\$ 81,001		
Average					\$ 128.94			\$ 133.72	\$ 4.78		
Percent										3.71%	

Clark Schedule "C-3": Three-Phase											
2009 Billing Determinants	Escalation %	Escalated Billing Determinants. (3)=(1)*(2)	Present		Actual Comp % of Base Rates	Proposed		Dollar Increase (7)	Percent Increase (8)	Proposed Comp.% of Base Rates	
			Rate (4)	Revenues (5)=(4)*(3)		Rate (6)	Revenues (7)=(6)*(3)				
			(1)	(2)		(3)	(4)				(5)
Customer Charge	2,050	1.27%	2,076	\$ 48.42	\$ 100,522	6.63%	\$ 50.42	\$ 104,674	\$ 4,152	6.63%	
Energy Charge per kWh	12,892,512	7.73%	13,889,103	\$ 0.10198	1,416,411	93.37%	\$ 0.10620	1,475,023	58,612	93.37%	
Demand Charge	-	-	-	\$ -	-	0.00%	\$ -	-	-	0.00%	
Billing Adjustments					-			-			
Total from Base Rates					1,516,932	100.00%		1,579,696	62,764	4.14%	
Plus Fuel Adjustment					27,466			27,466	-		
Plus Environmental Surcharge					88			88	-		
Total Revenues					\$ 1,544,486			\$ 1,607,250	\$ 62,764		
Average					\$ 743.96			\$ 774.19	\$ 30.23		
Percent										4.06%	

Clark Schedule "L"											
2009 Billing Determinants	Escalation %	Escalated Billing Determinants. (3)=(1)*(2)	Present		Actual Comp % of Base Rates	Proposed		Dollar Increase (7)	Percent Increase (8)	Proposed Comp.% of Base Rates	
			Rate (4)	Revenues (5)=(4)*(3)		Rate (6)	Revenues (7)=(6)*(3)				
			(1)	(2)		(3)	(4)				(5)
Customer Charge	1,324	1.27%	1,341	\$ 61.63	\$ 82,634	1.55%	\$ 64.18	\$ 86,053	\$ 3,419	1.55%	
Energy Charge per kWh	49,552,971	7.73%	53,383,416	\$ 0.07539	4,024,576	75.71%	\$ 0.07851	4,191,132	166,556	75.70%	
Demand Charge	193,404	0.00%	193,404	\$ 6.25	1,208,775	22.74%	\$ 6.51	1,259,060	50,285	22.74%	
Billing Adjustments					-			-			
Total from Base Rates					5,315,985	100.00%		5,536,245	220,260	4.14%	
Plus Fuel Adjustment					103,915			103,915	-		
Plus Environmental Surcharge					296,222			296,222	-		
Total Revenues					\$ 5,716,122			\$ 5,936,382	\$ 220,260		
Average					\$ 4,263			\$ 4,427	\$ 164.27		
Percent										3.85%	

Clark Energy
Billing Analysis
for the 12 months ended December 30, 2009

Clark Schedule "P"											
	2009 Billing Determinants (1)	Escalation % (2)	Escalated Billing Determinants. (3)=(1)*(2)	Present		Actual Comp % of Base Rates	Proposed		Dollar Increase (7)	Percent Increase (8)	Proposed Comp.% of Base Rates
				Rate (4)	Revenues (5)=(4)*(3)		Rate (6)	Revenues (7)=(6)*(3)			
Customer Charge	48	1.27%	49	\$ 83.91	\$ 4,079	0.48%	\$ 87.38	\$ 4,282	\$ 203		0.57%
Energy Charge per kWh	9,261,900	7.73%	9,977,845	\$ 0.0656	654,347	76.80%	\$ 0.06829	681,387	27,040		76.80%
Demand Charge	32,256	0.00%	32,256	\$ 6.00	193,536	22.72%	\$ 6.25	201,600	8,064		22.72%
Billing Adjustments					-			-	-		
Total from Base Rates					851,962	100.00%		887,269	35,307	4.14%	100.09%
Plus Fuel Adjustment					14,742			14,742	-		
Plus Environmental Surcharge					49,090			49,090	-		
Total Revenues					\$ 915,794			\$ 951,101	\$ 35,307		
Average					\$ 18,840			\$ 19,566	\$ 726.33		
Percent										3.86%	


Clark Schedule "M"											
	2009 Billing Determinants (1)	Escalation % (2)	Escalated Billing Determinants. (3)=(1)*(2)	Present		Actual Comp % of Base Rates	Proposed		Dollar Increase (7)	Percent Increase (8)	Proposed Comp.% of Base Rates
				Rate (4)	Revenues (5)=(4)*(3)		Rate (6)	Revenues (7)=(6)*(3)			
Customer Charge	12	0.00%	12	\$ -	\$ -		\$ -	\$ -	\$ -		
Energy Charge per kWh	8,584,872	0.81%	8,654,409	\$ 0.06886	595,942.64	77.34%	\$ 0.07171	620,608	24,665		77.34%
Demand Charge	17,840	0.59%	17,945	\$ 9.73	174,607.34	22.66%	\$ 10.13	181,785	7,178		22.66%
Billing Adjustments					-			-	-		
Total from Base Rates					770,549.98	100.00%		802,393	31,843	4.13%	100.00%
Plus Fuel Adjustment					7,051.00			7,051	-		
Plus Environmental Surcharge					45,472.00			45,472	-		
Total Revenues					\$ 823,073		rounding	\$ 854,916	\$ 31,843		
Average					\$ 68,589			\$ 71,243	\$ 2,653.60		
Percent										3.87%	

EXHIBIT 4
Page 1 of 1

CLARK ENERGY COOPERATIVE, INC.

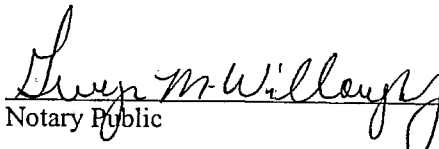
CASE NO. 2010-00170

I, Ann F. Wood, hereby certify that one complete copy of the materials filed with the Kentucky Public Service Commission has been sent to the Office of Rate Intervention, Office of the Attorney General.



Ann F. Wood
East Kentucky Power Cooperative, Inc.

Subscribed and sworn before me on this 27th day of May, 2010.



Notary Public

MY COMMISSION EXPIRES NOVEMBER 30, 2013
NOTARY ID #409352

EXHIBIT 5
Page 1 of 2

NOTICE OF PROPOSED RATE CHANGE

In accordance with the requirements of the Public Service Commission of the Commonwealth of Kentucky as set forth in 807 KAR 5:007, Section 3, of the Rules and Regulations of the Public Service Commission, notice is hereby given to the member consumers of Clark Energy Cooperative, Inc. of a proposed rate adjustment. An Application for Approval of Adjustment to Rates will be filed with the Public Service Commission on May 27, 2010, Case No. 2010-00170. The rates are being revised to reflect a change in wholesale rates pursuant to KRS 278.455(2). This adjustment will result in a general rate increase to the member-consumers of Clark Energy Cooperative, Inc. The amount and percent of increase by rate class are listed below.

<u>Rate Class</u>	<u>Increase</u>	<u>Percent</u>
Sch R: Residential	\$1,435,167	3.85%
Sch D: Time of Use Marketing	\$5,061	3.91%
Sch T: Outdoor Lighting Facilities	\$6,676	4.00%
Sch S: Outdoor Lighting Facilities	\$43,337	4.03%
Sch E: Public Facilities	\$19,894	3.85%
Sch C: General Power Service Single Phase	\$81,001	3.71%
Sch C: General Power Service Three Phase	\$62,764	4.06%
Sch L: General Power Service	\$220,260	3.85%
Sch P: General Power Service	\$35,307	3.86%
Sch M: General Power Service	\$31,843	3.87%

The effects of the proposed rates on the average monthly bill by rate class are listed below:

<u>Rate Class</u>	<u>\$ Increase</u>	<u>% Increase</u>
Sch R: Residential	\$4.87	3.85%
Sch D: Time of Use Marketing	\$1.76	3.91%
Sch T: Outdoor Lighting Facilities	\$0.75	4.00%
Sch S: Outdoor Lighting Facilities	\$0.40	4.03%
Sch E: Public Facilities	\$5.64	3.85%
Sch C: General Power Service Single Phase	\$4.78	3.71%
Sch C: General Power Service Three Phase	\$30.23	4.06%
Sch L: General Power Service	\$164.27	3.85%
Sch P: General Power Service	\$726.33	3.86%
Sch M: General Power Service	\$2,653.60	3.87%

The present and proposed rates structures of Clark Energy Cooperative, Inc. are listed below:

<u>Rate Class</u>	<u>Present</u>	<u>Proposed</u>
Sch R: Residential		
Facility Charge per month	\$12.00	\$12.50
Energy charge per kWh	\$0.095773	\$0.099734
Sch D: Time of Use Marketing		
Per kWh for all energy	\$0.06489	\$0.06757

EXHIBIT 5
Page 2 of 2

<u>Rate Class</u>	<u>Present</u>	<u>Proposed</u>
Sch T: Outdoor Lighting Facilities (per month)		
400 watt	\$18.07	\$18.82
Sch S: Outdoor Lighting Facilities (per month)		
175 watt	\$9.75	\$10.15
Sch E: Public Facilities		
Facility Charge per month	\$16.00	\$16.66
Energy charge per kWh	\$0.10248	\$0.10672
Sch C: General Power Service Single Phase		
Facility Charge per Month	\$24.46	\$25.47
Per kWh for all Energy	\$0.10198	\$0.10620
Sch C: General Power Service Three Phase		
Facility Charge per Month	\$48.42	\$50.42
Per kWh for All Energy	\$0.10198	\$0.10620
Sch L: General Power Service		
Facility charge per Month	\$61.63	\$64.18
Demand charge per kW	\$6.25	\$6.51
Energy charge per kWh	\$0.07539	\$0.07851
Sch P: General Power Service		
Facility charge per Month	\$83.91	\$87.38
Demand charge per kW	\$6.00	\$6.25
Energy charge per kWh	\$0.06558	\$0.06829
Sch M: General Power Service		
Demand charge per kW	\$9.73	\$10.13
Energy charge per kWh	\$0.06886	\$0.07171

The rates contained in this notice are the rates proposed by Clark Energy Cooperative, Inc. However, the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice. Such actions may result in rates for consumers other than the rates in this notice.

Any person may examine the rate application at the main office of Clark Energy Cooperative, Inc at the following address:

Clark Energy Cooperative, Inc.
2640 Iron Works Road
Winchester, KY 40391
(859) 744-4251
www.clarkenergy.com

Any person may also examine the rate application at the office of the Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky.

**RJM-19 - KEPCo Response to
Mid-Kansas Data Request No. 16**

**Mid-Kansas and Southern Pioneer
Information Request**

Request No: 16

Company Name: KEPCo
Docket Number: 12-MKKEE-380-RTS
Request Date: April 24, 2012
Response Due Date: May 8, 2012

Please Provide the Following:

Please reference page 28, lines 1-4 of Mr. Stephen Daniel's Direct testimony.

- a. Please identify and provide reference documentation for instances in which Mr. Daniel has recommended that an electric utility base its rates at the lender minimum loan covenant requirements.

Response: None. The cited testimony is based upon the unique facts and circumstances pertinent to Southern Pioneer. Mr. Daniel has not encountered similar situations with other regulated electric utilities.

- b. Has Mr. Daniel ever made a recommendation to an electric utility client that rates be set to recover something greater than the utility's minimum loan covenant requirements?

Response: Yes, where there were no perceived mitigating circumstances.

Submitted By: Mid-Kansas/Southern Pioneer

Submitted To: KEPCo

If for some reason the above information cannot be provided by the date requested please provide a written explanation of the reason(s).

Verification of Response

I have read the foregoing Information Request and answer(s) thereto and find the answer(s) to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the

best of my knowledge and belief; and I will disclose to the requestor any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Data Request.

Signed: Stephen Page Daniel

Dated: 5-8-12

**RJM-20 - Staff Response to Mid-
Kansas Data Request No. 10**

**Mid-Kansas and Southern Pioneer
Information Request**

Request No: 10

Company Name: KCC Staff
Docket Number: 12-MKEE-380-RTS
Request Date: April 25, 2012
Response Due Date: May 9, 2012

Please Provide the Following:

Please reference Staff Schedule B-1. Provide the following under Staff's recommended \$2,879,566 increase.

- a. Staff's calculation of Southern Pioneer's DSC using the CoBank loan covenant formula referenced and described on page 11 of Ms. Laura Bowman's Direct testimony and as contained on page 3, line 4 of Mr. Adam Gatewood's Direct testimony.
- b. Staff's calculation of Southern Pioneer's O-DSC under Staff's proposed \$2,879,566 increase.

Response:

- a) Based on Staff's proposed \$2,879,566 revenue requirement, the DSC calculation using the CoBank loan covenant formula would result in a DSC ratio of 1.79. See below for the calculation:

Net Margin	4,956,351
Plus: Depreciation	1,983,315
Plus: Amortization (RUS)	322,880
Plus: Interest Expense	4,547,758
Plus: Non-Operating Income	9,415
Plus: Cash Capital Credits	550,474
Less: Non-cash Patronage	(642,263)
Less: K-1 Income	(1,474,761)
	<hr/>
	10,253,169
Principle and Interest	5,743,604
Co-Bank DSC Ratio	<hr/> <u>1.79</u>

b) Based on Staff's proposed \$2,879,566 revenue requirement and using Southern Pioneer's O-DSC methodology would result in a DSC ratio of 1.79. See below for the calculation:

Net Margin	4,956,351
Plus: Depreciation	1,983,315
Plus: Interest on LT Debt	4,547,758
Plus: Other Deductions	322,880
	<hr/>
	11,810,304
Less: Non-Cash K-1	1,474,761
Less: Non-Cash AP Amortization	0
Less: Non-Cash Capital Credits	642,263
Plus: Cash Non-Operating Income	9,415
Plus: Cash Capital Credits	550,474
Less: Income Tax	0
	<hr/>
	(1,557,135)
DSC Margins - Proposed Rates	10,253,169
Debt Service	5,743,604
O-DSC	<hr/> <hr/>
	1.79

Please note: Staff did not calculate either DSC ratio above and does not support the outcome of either ratio. The ratio calculated above was only calculated in response to the above data request.

Submitted By: Mid-Kansas/Southern Pioneer

Submitted To: Commission Staff

If for some reason the above information cannot be provided by the date requested please provide a written explanation of the reason(s).

Verification of Response

I have read the foregoing Information Request and answer(s) thereto and find the answer(s) to be true, accurate, full and complete, and contain no material misrepresentations or omissions to the best of my knowledge and belief, and I will disclose to the requestor any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Data Request.

Signed: _____

Dated: _____

