

**BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS**

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**In the Matter of the Application of)
Mid-Kansas Electric Company, LLC)
for Approval to Make Certain Changes)
in its Charges for Electric Service in the)
Geographic Service Territory Served by)
Southern Pioneer Electric Company.)**

Docket No. 12-MKEE-380-RTS

**DIRECT TESTIMONY AND EXHIBITS OF
STEPHEN PAGE DANIEL**

**ON BEHALF OF
KANSAS ELECTRIC POWER COOPERATIVE, INC.**

APRIL 20, 2012

LIST OF EXHIBITS

Exhibit No.	Title
SPD-1	Resume of Stephen Page Daniel
SPD-2	Supporting Source Documents

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1

I. INTRODUCTION

2 **Q. Please state your name and business address.**

3 A. My name is Stephen Page Daniel. My business address is 1850 Parkway Place,
4 Suite 800, Marietta, Georgia 30067.

5 **Q. By whom are you employed and in what capacity?**

6 A. I was a founding principal of and currently an Executive Consultant with GDS
7 Associates, Inc. (“GDS” or “GDS Associates”), a multi-disciplined engineering and
8 consulting firm.

9 **Q. Please outline your formal education.**

10 A. I received a Bachelor of Industrial Engineering degree from Georgia Institute of
11 Technology in 1970. I received a Master of Business Administration degree with a major
12 in finance from Georgia State University in 1978.

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1 **Q. To what professional organizations do you belong?**

2 A. I am a member of the Institute of Electrical and Electronics Engineers.

3 **Q. What are your consulting duties and responsibilities with GDS Associates?**

4 A. My primary responsibilities involve providing rate and regulatory services related
5 to electric utility industry matters and consulting services with regard to electric system
6 power supply planning, including strategic planning for transmission resources and
7 access, and electric industry restructuring/deregulation matters.

8 **Q. Please briefly describe your professional experience.**

9 A. Prior to founding GDS Associates in early 1986, I worked for approximately
10 fifteen (15) years with another consulting engineering firm. During that time, my
11 positions and responsibilities changed from initially a rate analyst to Assistant Vice
12 President, Rate and Analytical Services.

13 As a consultant over the last forty-two (42) years, I have had primary
14 responsibility for assignments pertaining to wholesale rates, retail rates, financial
15 planning, power supply planning for electric utilities, transmission access, and electric
16 industry restructuring/deregulation policy development and implementation. My various
17 assignments have been on behalf of more than two hundred and fifty (250) cooperative
18 and municipal electric systems, several industrial clients, several investor-owned utilities,
19 and several regulatory commissions in forty-one (41) states. My responsibilities have
20 included the preparation of allocated cost-of-service studies, retail and wholesale rate
21 design studies, financial forecasts, revenue requirements evaluations, and analyses of
22 alternative power supply resources. These activities have also involved the negotiation of

1 bulk power contracts and transmission service arrangements, including ancillary services
2 procurement and implementation.

3 I also have analyzed cost-of-service studies filed by others with the Federal
4 Energy Regulatory Commission (“FERC”) and various state regulatory commissions.

5 My responsibilities also have included assignments in the specialized areas of rate
6 design for unusual loads, evaluation of financing alternatives, acquisition and merger
7 feasibility and market power related issues, and regulatory rulemaking.

8 I have attached a copy of my current résumé as Exhibit SPD-1 for further
9 reference to my professional experience.

10 **Q. Have you previously testified before regulatory commissions?**

11 A. I have testified before the Alabama Public Service Commission, Alaska Public
12 Utilities Commission, Arizona Corporation Commission, Arkansas Public Service
13 Commission, Colorado Public Utilities Commission, Florida Public Service Commission,
14 Georgia Public Service Commission, Public Service Commission of Indiana, Kansas
15 Corporation Commission (“Commission”), Louisiana Public Service Commission,
16 Michigan Public Service Commission, Mississippi Public Service Commission, Public
17 Utility Commission of Nevada, North Carolina Utilities Commission, Pennsylvania
18 Public Utility Commission, South Carolina Public Service Commission, Public Utility
19 Commission of Texas, Utah Public Service Commission, Virginia State Corporation
20 Commission, and West Virginia Public Service Commission.

21 I also have testified before the FERC (formerly the Federal Power Commission)
22 in more than twenty (20) cases. And, I have filed affidavits before the FERC and have

1 filed testimony in other FERC proceedings which ultimately were settled before the trial
2 phase.

3 **Q. Have you testified as an expert witness in court proceedings?**

4 A. Yes. I have testified or filed affidavits in Federal District Courts (NE, SC and
5 TN), Federal Bankruptcy Court (LA), the Supreme Court of the State of New York and
6 several other state courts.

7 **Q. Do you consult with regard to transmission and distribution arrangements
8 on behalf of your clients?**

9 A. Yes. Because transmission facilities and transmission access are vital to the
10 development of comprehensive power supply plans, I am involved on a regular basis in
11 the assessment of transmission needs and the determination of appropriate terms,
12 conditions, and pricing (including cost allocation) of transmission access arrangements.
13 My activities in this area include the negotiation of transmission tariffs, complex
14 transmission service contracts, service agreements and operating agreements under open
15 access transmission tariffs, and joint participation arrangements on behalf of a number of
16 clients across the country. These assignments have included the establishment of
17 distribution-level charges for wholesale transmission services.

18 **Q. Do your job responsibilities require you to consult in the areas of power
19 supply planning, power supply feasibility, and power supply economics in general?**

20 A. Yes. Periodically I assist clients with evaluating the feasibility of power supply
21 alternatives. On several occasions I have participated as part of a project team on power
22 supply economic studies and power supply negotiations. Examples of these power
23 supply areas are: evaluation of alternative power sources for public power systems such

1 as municipals, generation and transmission cooperatives, and distribution cooperatives;
2 negotiation of bulk power purchases and sales contracts; negotiation of joint ownership
3 agreements for generating plants; negotiation of interconnection and interchange
4 agreements; negotiation of transmission service contracts, including ancillary services,
5 and joint transmission participation arrangements; and development of generation support
6 services arrangements. Work on rate cases before state commissions and the FERC
7 requires a varying intensity of power supply evaluation for purposes such as cost
8 allocation and rate design.

9 I also have been involved in various matters involving the establishment of the
10 pricing terms and conditions of ancillary services and the implementation of such
11 services. For example, I have participated in at least a dozen open access transmission
12 proceedings involving ancillary services. I also have negotiated a number of
13 transmission services contracts involving various ancillary services applicability and
14 implementation issues.

15 **Q. On whose behalf are you appearing in this proceeding?**

16 A. I am presenting testimony on behalf of Kansas Electric Power Cooperative, Inc.
17 (“KEPCo”).

18 **Q. Please describe KEPCo’s interest in Mid-Kansas Electric Company, LLC’s**
19 **(“MKEC” or “Mid-Kansas”) filing in this proceeding associated with its Southern**
20 **Pioneer Division and the facilities of Southern Pioneer Electric Company**
21 **(“Southern Pioneer”).**

22 A. KEPCo purchases wholesale transmission service under Schedule LAC
23 (Application, Exhibit RJM-9, Index No. 24, with proposed rate as calculated in Exhibit

1 RJM-5, pp. 1-5) for the transmission of power from MKEC's transmission facilities to
2 KEPCo's delivery points served through Southern Pioneer's sub-transmission facilities.
3 KEPCo has a significant interest in the rates and charges applicable to such wholesale
4 transmission service under Schedule LAC involving Southern Pioneer's facilities.

5 **II. NATURE AND PURPOSE OF TESTIMONY**

6 **Q. What are the nature and purpose of your pre-filed direct testimony?**

7 A. My testimony will address two (2) major issues regarding MKEC's proposed
8 rates to be applicable for the geographic service territory served by Southern Pioneer: (1)
9 the appropriate balancing of the respective interests of Southern Pioneer and its
10 customers; and (2) the reasonableness of the proposed utilization of a Debt Service
11 Coverage ("DSC") Ratemaking Plan ("DSC Plan") for automatic recovery of costs plus
12 attainment of certain proposed financial performance DSC metrics.

13 **Q. What materials have you reviewed in preparation for the presentation of**
14 **your pre-filed direct testimony?**

15 A. I have reviewed the following materials:

- 16 • MKEC's Application in Docket No. 12-MKEE-380-RTS, including the
17 direct testimonies of Mr. Stuart S. Lowry ("Lowry Direct"), Mr. Stephen
18 J. Epperson ("Epperson Direct"), Mr. Chantry. C. Scott ("Scott Direct")
19 and Mr. Richard J. Macke ("Macke Direct") and their respective exhibits;
- 20 • MKEC's and Southern Pioneer's responses to KEPCo's discovery;
- 21 • MKEC's and Southern Pioneer's responses to selected data requests of
22 other parties to this proceeding;
- 23 • MKEC's and Southern Pioneer's responses to selected data requests of
24 Commission Staff;

1 The customers' interest is in receiving service at the lowest reasonable cost
2 consistent with industry norms for reliability of service and prudence of actions on the
3 part of their supplying utility.

4 These respective interests of the utility and its customers inherently are potentially
5 adverse. Because these interests are potentially adverse, there must be a balancing of
6 those respective interests by the regulator to achieve a result that is in the overall public
7 interest.

8 **Q. Do the respective interests of MKEC and Southern Pioneer on the one hand
9 and their customers on the other exemplify the relationships that you just described
10 which necessitate that there be a balancing of those respective interests?**

11 A. Yes. The rates to be established in this proceeding are to recover Southern
12 Pioneer's costs of providing services to its various retail customers and wholesale
13 transmission customers. Southern Pioneer is structured as a taxable C-corporation
14 pursuant to the Internal Revenue Service Code (Lowry Direct, p. 5, ll. 13-14). It is a for-
15 profit entity. Southern Pioneer is wholly owned by Pioneer Electric Cooperative, Inc.
16 ("Pioneer") (*id.*, p. 3, ll. 8-9; Epperson Direct, p. 6, ll. 2-4). Southern Pioneer's
17 customers are not members or owners of Southern Pioneer (or Pioneer), as is the case in a
18 not-for-profit cooperative form of utility. All earnings of Southern Pioneer go to the
19 owner, in this case Pioneer, and not to the benefit of Southern Pioneer's customers, as
20 would be the case were Southern Pioneer structured as a not-for-profit cooperative
21 (Exhibit SPD-2, pp. 1-2).

1 To the extent Southern Pioneer's customers are charged more than is just and
2 reasonable, based upon prudently incurred costs, the excess charges inure to the benefit
3 of Pioneer to the detriment of Southern Pioneer's customers.

4 There is, therefore, a delicate balance between the interest of Southern Pioneer as
5 a for-profit, taxable C-corporation and its customers who have no pecuniary interest in
6 Southern Pioneer. In recognition of this relationship, the Commission should consider all
7 aspects of how Southern Pioneer has chosen to structure and operate its system in
8 determining the appropriate rates to be charged Southern Pioneer's customers in the
9 Southern Power Division.

10 **B. ADVERSE IMPLICATIONS OF SOUTHERN PIONEER'S C-**
11 **CORPORATION BUSINESS STRUCTURE**

12 **Q. Mr. Stuart S. Lowry, on behalf of MKEC and Southern Pioneer, takes the**
13 **position that "Southern Pioneer agreed to operate as any other similarly situated**
14 **not-for-profit taxable entity and not remit dividends to its sole shareholder Pioneer**
15 **Electric without KCC and the lender approvals" (Lowry Direct, p. 5, ll. 14-16;**
16 **footnote omitted). Please respond to this proposition.**

17 A. The first important point with regard to this statement is the fact that Southern
18 Pioneer is not a not-for-profit, taxable (or non-taxable) entity. Southern Pioneer must
19 generate a profit in order to meet its financial obligations to its lender, CoBank. For
20 Southern Pioneer to meet its DSC obligations with CoBank, it must earn a profit, which
21 MKEC euphemistically refers in its Application as a margin requirement (*see, e.g.,*
22 Exhibit RJM-3, p. 1, ll. 6-8 and 22-24 and Exhibit RJM-5, p. 1, l. 13). While income in
23 excess of expenses in the context of a not-for-profit cooperative constitutes margins,

1 revenues in excess of expenses (before income taxes) in the context of a for-profit,
2 taxable entity constitutes taxable income. As a result of this taxability of income,
3 Southern Pioneer potentially will be required to pay income taxes. Since the DSC
4 financial test is applied to net (*i.e.*, after-tax) income, MKEC has included a component
5 of costs for income taxes to achieve sufficient net income for Southern Pioneer to meet
6 its DSC obligations to CoBank. This computation of income taxes as a component of
7 costs is demonstrated in Southern Pioneer's revenue requirements calculations (*id.*).

8 If Southern Pioneer were structured as a not-for-profit cooperative, it would not
9 be required to incorporate a component for income taxes unless its sources of revenues
10 violated the underpinning statutory provisions for maintaining its non-taxable cooperative
11 status, which would otherwise make it non-taxable. Hence, Southern Pioneer's for-profit,
12 taxable C-corporation status is, in reality, not similarly situated to a not-for-profit
13 cooperative, whether or not such cooperative were a taxable entity.

14 **Q. Does a pledge not to remit dividends to Pioneer in any way affect your**
15 **conclusion on this point?**

16 A. No. The net (*i.e.*, after-tax) profits (or so-called margins) of Southern Pioneer are
17 the property of Southern Pioneer's sole shareholder, Pioneer, regardless of whether
18 Southern Pioneer remits or does not remit dividends to Pioneer. Southern Pioneer's
19 customers have no ownership interest in Southern Pioneer, therefore, they have no claim
20 to the equity ownership in Southern Pioneer created by virtue of Southern Pioneer
21 operating at a profit. In stark contrast, the member/ratepayers of a cooperative are the
22 owners of the cooperative, and the margins earned by a cooperative are vested with those
23 owners in the form of patronage capital assignments. Southern Pioneer's customers have

1 no such equity rights emanating from the profits earned by Southern Pioneer. This fact is
2 not in any way a function of whether Southern Pioneer does periodically or does not
3 remit dividends to its sole shareholder, Pioneer.

4 If dividends are not remitted by Southern Pioneer to Pioneer, those funds are
5 available to reinvest in Southern Pioneer assets. At the end of the day, however, those
6 assets are the property of Southern Pioneer's owner, Pioneer, and not Southern Pioneer's
7 customers. This ownership relationship further illustrates two key points: (1) Southern
8 Pioneer's corporate structure and operation in no meaningful way reflect how a member-
9 owned, not-for-profit cooperative (such as Pioneer) operates; and (2) there is an obvious
10 dichotomy in the interest of Southern Pioneer and its sole shareholder, Pioneer, on the
11 one hand and Southern Pioneer's customers who have no vested ownership-interest in
12 Southern Pioneer on the other.

13 **Q. Mr. Lowry, on behalf of MKEC, also states that "Southern Pioneer is**
14 **operated much like a consumer-owned cooperative in that there are no competing**
15 **interests between the stockholders and customers" (Lowry Direct, p. 5, ll. 16-18).**
16 **Do you agree with this conclusion?**

17 A. No. For all the reasons I have previously noted, there are substantial differences
18 in the interest of the stockholder(s) of a for-profit, taxable C-corporation and the interest
19 of its customers.

20 **Q. Mr. Stephen J. Epperson, on behalf of MKEC and Southern Pioneer, states**
21 **that "the chosen business structure [of Southern Pioneer (i.e., for-profit, taxable C-**
22 **corporation)] does not negatively affect Mid-Kansas customers" (Epperson Direct,**
23 **p. 5, l. 22). Is this claim correct?**

1 A. No. As I previously noted, because Southern Pioneer is taxable, there is a
2 component of costs imputed for income taxes in the derivation of Southern Pioneer's
3 revenue requirements. Since Southern Pioneer customers will have to pay this income
4 tax component due to the profitability of Southern Pioneer, the customers are negatively
5 affected by the for-profit, taxable C-corporation business structure chosen by Southern
6 Pioneer.

7 **Q. Mr. Epperson also states in defense of Southern Pioneer's structure that**
8 **"Southern Pioneer agreed to operate as any other similarly situated, not-for-profit**
9 **taxable entity and not remit dividends to its sole shareholder Pioneer without KCC**
10 **and lender approvals" (id., p. 6, ll. 2-4). Please address this claim.**

11 A. His claim is identical to the claim also made by Mr. Lowry regarding this chosen
12 structure. Mr. Epperson's conclusion is wrong for all the reasons which I put forth in
13 response to Mr. Lowry's same claim.

14 **Q. In further defense of Southern Pioneer's chosen business structure, Mr.**
15 **Epperson states that "rather than distribute excess revenues or margins, if any, to**
16 **its sole shareholder Pioneer, Southern Pioneer pledged to reinvest these monies in**
17 **Mid-Kansas' Southern Pioneer Division to create a local presence, enhance service**
18 **and increase long-term reliability" (id., ll. 6-9). Please address this point in the**
19 **context of the for-profit, taxable C-corporation business structure chosen by**
20 **Southern Pioneer.**

21 A. If Southern Pioneer had chosen to structure itself as a not-for-profit, non-taxable
22 cooperative, it would be required to generate through revenues the same margins (*i.e.*,
23 profits) that it seeks to generate through rates as a taxable entity in order to meet its DSC

1 requirements under its lending arrangements with CoBank. By choosing the taxable C-
2 corporation structure, the Southern Pioneer customers will have to pay an additional
3 increment of costs in the form of income taxes in order to achieve the same level of
4 margins that would otherwise be achieved as a non-taxable cooperative. Those margins
5 (or profits), whether earned under a taxable, C-corporation structure or under a not-for-
6 profit cooperative structure would be available under either scenario to reinvest in
7 Southern Pioneer Division facilities for the purposes cited by Mr. Epperson. Contrary to
8 his claim of no negative effect on MKEC customers, there is a clear and unjustifiable
9 negative effect on those customers in the form of imposed income tax expenses that could
10 have been avoided under a not-for-profit cooperative business structure. And, of course,
11 as I noted previously, those margins in a cooperative structure would be vested with the
12 member/ratepayers (*i.e.*, customers) under the cooperative structure, where those equity
13 amounts belong solely to Pioneer under the C-corporation business structure.

14 **Q. Had Southern Pioneer been structured as a not-for-profit cooperative, would**
15 **it have been required to distribute the margins (*i.e.*, revenues in excess of expenses)**
16 **to its members/ratepayers?**

17 A. No. Patronage capital rotation plans are usually adopted by a cooperative based
18 upon its individual circumstances. In a situation such as that of Southern Pioneer, which
19 was financed initially with virtually all debt, there is a need to generate equity. There
20 would be no requirement that a cooperative retire capital credits, which are accrued
21 margins assigned as patronage capital to each member/ratepayer, so long as the
22 cooperative did not meet certain financial objectives (*e.g.*, lender requirements) with
23 regard to an acceptable level of equity ownership. Had Southern Pioneer elected a not-

1 for-profit cooperative business structure, it would have had the same level of margins or
2 profits available to it to reinvest in the system as it would under the taxable, C-
3 corporation structure, given the same target DSC under either such structure. There is no
4 basis upon which to suggest that somehow the customers are not negatively affected by
5 the for-profit, taxable C-corporation structure under the circumstances, given the
6 unnecessary income tax ramifications.

7 **Q. What is the amount of Southern Pioneer's income tax component of its**
8 **proposed revenue requirement for Schedule LAC?**

9 A. Of the total proposed Schedule LAC revenue requirement of \$3,439,611 (Exhibit
10 RJM-5, p. 1, l. 19), the income tax component is \$452,985 or 13.17% (*id.*, l. 17). This
11 imputed income tax component is a major part of the Schedule LAC revenue
12 requirement.

13 **Q. Did any of the other MKEC owners besides Southern Pioneer elect to**
14 **structure and operate their assets acquired from Aquila through MKEC as a for-**
15 **profit, taxable C-corporation?**

16 A. No. Southern Pioneer is the only one of the six (6) MKEC owners that elected to
17 structure and operate its acquired assets as a for-profit, taxable C-corporation.

18 **Q. Did the Stipulation and Agreement filed January 10, 2007, in Docket 524**
19 **address income tax in MKEC rate filings?**

1 A. Yes. Paragraph 24 of the Stipulation and Agreement states: “MKEC agrees to not
2 include an income tax expense component in any MKEC rate filing before the
3 Commission.”¹

4 **Q. Does MKEC still hold the certificate to provide electric service in the
5 Southern Pioneer Division geographic service territory?**

6 A. Yes, it does.

7 **Q. Is the current docket an MKEC rate filing?**

8 A. Yes, it is. This is a filing by MKEC for approval to make changes in its charges
9 for electric service in the geographic service territory served by Southern Pioneer. Given
10 that MKEC holds the certificate to provide electric service in the Southern Pioneer
11 service territory, the current and proposed tariffs that are a subject of this proceeding are
12 clearly and appropriately designated as MKEC tariffs, applicable to service in its
13 “Southern Pioneer Division” (Exhibits RJM-9 and RJM-10).

14 **Q. Is MKEC’s rate filing for the Southern Pioneer Division consistent with its
15 commitment and obligation under the Stipulation and Agreement in Docket 524 not
16 to include an income tax expense component in any MKEC rate filing?**

17 A. No. Clearly, MKEC’s filing violates this commitment and obligation by
18 including an income tax expense component.

¹ *In the Matter of the Joint Application of Aquila, Inc., d/b/a Aquila Networks – WPK (WPK) and Mid-Kansas Electric Company, LLC (MKEC), Joint Applicants, for an Order Approving the Transfer of Certificates of Convenience and Franchises with Respect to All of WPK’s Kansas Electric Business, Including its Generation, Transmission and Local Distribution Facilities Located in the State of Kansas, and for Other Related Relief (“MKEC Aquila Acquisition”), Docket No. 06-MKEE-524-ACQ, Stipulation & Agreement, January 10, 2007, ¶ 24.*

1 **C. ADVERSE IMPLICATIONS OF SOUTHERN PIONEER’S**
2 **DECISION TO RE-FINANCE ITS FFB DEBT**

3 **Q. How is Southern Pioneer financed?**

4 A. Mr. Epperson describes the financing with regard to Southern Pioneer as follows:

5 It is common knowledge that the acquisition of the Aquila territory
6 was one hundred percent debt financed. This fact, coupled with
7 the known subsequent capital investments and the replacement
8 expense associated therewith to date, resulted in negative to near
9 zero equity for Southern Pioneer.

10 Epperson Direct, p. 7, ll. 13-16. It is clear that Southern Pioneer is virtually 100% debt
11 financed. Only as its cost-recovery produces net income will Southern Pioneer be able to
12 create retained equity as a form of financing.

13 **Q. Where does Southern Pioneer obtain its debt financing?**

14 A. Until October 24, 2011, “Southern Pioneer’s RUS [(i.e., Rural Utilities Service)]
15 debt was held by the Federal Finance [sic] bank (FFB)” (Scott Direct, p. 3, l. 16). “On
16 October 24, 2011, Southern Pioneer closed on a new \$84,688,239 loan from CoBank,
17 which was used to buy out of its long-term debt obligations with RUS, pay off its existing
18 operating line of credit with CoBank, and established [sic] available funds for continuing
19 necessary capital construction projects as specified in Southern Pioneer’s construction
20 work plan” (*id.*, p. 3, l. 21 – p. 4, l. 2).

21 **Q. What were the effects on Southern Pioneer’s customers of its decision to buy**
22 **out of its long-term debt with FFB and to replace it with debt from CoBank?**

23 A. Southern Pioneer’s decision to replace its FFB debt with CoBank debt would have
24 two immediate effects on its customers. One, Southern Pioneer was required to pay a
25 \$9,686,404 prepayment penalty to FFB for early retirement of the FFB debt (Exhibit
26 SPD-2, p. 4). This prepayment is being amortized over 30 (*id.*, p. 5) years and the cost

1 effect is proposed to be recovered through rates charged to Southern Pioneer's customers
2 in the amount of \$322,880 per year (Exhibit RJM-3, p. 1, l. 12, col. (c)). Had Southern
3 Pioneer not refinanced its FFB debt, its customers would have been spared the cost
4 associated with this prepayment penalty, both the principal, the interest incurred to
5 finance it, and the associated DSC requirements.

6 Two, borrowings from CoBank will result in higher costs to Southern Pioneer's
7 customers than had it maintained its FFB debt. This conclusion is based upon a
8 presentation made to Southern Pioneer's Board of Directors on (*id.*, pp. 6-26), which
9 shows higher interest expense and debt service requirements with the CoBank financing.

10 **Q. Has MKEC or Southern Pioneer presented any empirical evidence that**
11 **quantifies any offsetting benefits to Southern Pioneer of the adverse effects of the**
12 **prepayment penalty and higher debt costs that negatively impact Southern**
13 **Pioneer's customers?**

14 A. No. Mr. Chantry C. Scott, on behalf of MKEC and Southern Pioneer, posits two
15 subjective arguments in support of Southern Pioneer's decision to buy out of its FFB
16 financing. He states that "[t]he first is the uncertainty of future RUS funding, and the
17 second is the negative impact of RUS-prolonged approval process for construction work
18 plan loans and other associated activities" (Scott Direct, p. 4, ll. 11-14). Neither of these
19 stated reasons for incurrence of higher-cost debt is supported by any empirical evidence
20 showing that such higher financing costs are offset by other cost-reducing benefits.

21 He defends his first subjective point by noting that "[p]rior administrations have
22 attempted to eliminate allocations to RUS to trim government spending and, coupled with
23 down economy and increasing national deficit, RUS funding may be constrained in future

1 years” (*id.*, ll. 18-20). I have provided consulting services to RUS-financed (including
2 FFB-financed) cooperatives since the early 1970’s. During virtually every presidential
3 administration over the ensuing 40+ years there have been ebbs and flows in the level of
4 federal funding for rural electric cooperatives, restructurings of the availability of federal
5 funds, and the introduction of supplemental lending programs. Notwithstanding the
6 uncertainties associated with such changes over time, the vast majority of rural electric
7 cooperatives remain RUS-financed borrowers. The uncertainty suggested by Mr. Scott
8 has not resulted in a major trend by electric cooperatives to buy out of their RUS
9 financing.

10 **Q. Please address Mr. Scott’s second reason for buying out of its long-term FFB**
11 **debt, namely the prolonged approval process.**

12 A. Each RUS (and FFB) borrower faces the same processes with regard to securing
13 loan funds. The slower processes of RUS/FFB, however, have not, in my experience,
14 caused a major buy-out of RUS/FFB debt in favor of other sources of debt financing,
15 particularly those which might be more costly than RUS/FFB financing. Again, Southern
16 Pioneer’s stated motive is subjective and without any empirical evidence that there are
17 offsetting, cost-reducing benefits to its customers that overcome the FFB prepayment
18 penalty and the higher-cost CoBank financing.

19 **Q. Are you aware of cooperative RUS borrowers that have taken steps to**
20 **mitigate the effects of the prolonged approval process?**

21 A. Yes, for instance, I am advised that KEPCo has utilized short-term unsecured
22 financing to bridge the time required to obtain long-term secured financing for its Wolf

1 Creek capital additions needs. Presumably, such short-term financing would be available
2 to other RUS borrowers.

3 **Q. In the absence of empirical evidence that there are offsetting, cost-reducing**
4 **benefits to the customers, what action should the Commission take regarding these**
5 **higher financing costs?**

6 A. There is a range of options. The Commission could disallow all financing costs in
7 excess of those available from the RUS. As an alternative, the Commission could allow
8 the higher interest costs imposed by using CoBank, but disallow the prepayment penalty
9 which causes a double harm. The customers are being asked to pay not only a recovery
10 of the amortized prepayment penalty but are also paying the higher interest rate on the
11 unpaid balance.

12 **D. ADVERSE IMPLICATIONS OF THE ACQUISITION PREMIUM**
13 **PAID BY SOUTHERN PIONEER**

14 **Q. Please explain what an acquisition premium is in a regulated utility rate**
15 **context.**

16 A. Most typically, utilities are allowed to recover actual costs for ratemaking
17 purposes, including return on and return of the original cost for the assets when initially
18 dedicated to utility service. This is the concept of ratemaking based upon original book
19 cost. Generally, most utilities follow some form of accounting that is generally reflective
20 of the Uniform System of Accounts prescribed by the FERC. When regulated utilities
21 acquire assets from another entity at a price greater than original cost, the acquiring
22 utility is deemed to have paid an acquisition premium, which is the amount of the
23 purchase price in excess of net book value based upon original cost.

1 **Q. How is an acquisition premium treated for ratemaking purposes?**

2 A. Typically, state regulatory bodies address the appropriate ratemaking treatment of
3 acquisition premiums on a case-by-case basis. The ratemaking treatment can range from
4 total denial of recovery of the acquisition premium (both amortization of the acquisition
5 premium and a rate of return on the unamortized balance of the acquisition premium) to
6 complete recovery in rates, including both amortization of the acquisition premium and
7 allowance for a return on the unamortized balance of the acquisition premium. Between
8 these two polar-opposite treatments there is a range of other ratemaking treatments that
9 can be employed. For example, the regulatory authority may allow amortization of the
10 acquisition premium but disallow a return on the unamortized balance of the acquisition
11 premium. In addition, there is discretion with regard to the period over which an
12 acquisition premium may be amortized, such as for a stated period (*e.g.*, 10 years) or the
13 remaining life of the acquired assets.

14 **Q. What criteria are used to determine the appropriate ratemaking treatment**
15 **for acquisition premiums?**

16 A. The most common criteria are prudence and the extent to which there may be
17 offsetting benefits to the affected ratepayers of the involved acquisition.

18 **Q. When MKEC purchased the Aquila assets that it ultimately spun down to**
19 **Southern Pioneer, did the purchase price include an acquisition premium?**

20 A. Yes. As of December 31, 2010, that acquisition premium was \$21,207,399 (*id.*,
21 p. 28).

1 **Q. Are MKEC and Southern Pioneer seeking cost recovery for that acquisition**
2 **premium in the establishment of Southern Pioneer's proposed rates in this**
3 **proceeding?**

4 A. Yes. That acquisition premium was financed as part of the CoBank debt, so the
5 associated interest expense and debt service for the portion of the total outstanding debt
6 from time-to-time related to the acquisition premium is proposed to be recovered in
7 Southern Pioneer's revenue requirements. The annual amortization is \$785,460 (Exhibit
8 RJM-2, p. 18, l. 2; $\$65,455/\text{mo.} \times 12 = \$785,460$).

9 **Q. Has MKEC or Southern Pioneer presented any information to demonstrate**
10 **that there are benefits associated with the acquisition that offset the higher costs to**
11 **Southern Pioneer's customers associated with paying and recovering through rates**
12 **the associated costs of the acquisition premium which it paid?**

13 A. No. Neither empirical nor subjective information has been presented to
14 demonstrate that any customer benefits associated with the acquisition premium offset, in
15 whole or in part, the adverse cost effects of the acquisition premium paid for the Aquila
16 assets.

17 **Q. Did Docket 524 contemplate the recovery of the acquisition premium from**
18 **MKEC customers?**

19 A. Though I was not engaged directly in a review of the Docket 524, from a review
20 of the Stipulation and Agreement, it appears that recovery of the acquisition premium
21 from MKEC customers was allowed, though in a rather indirect manner. Under
22 paragraph 21 of the Stipulation and Agreement in the Docket 524, the acquisition
23 premium was to be amortized over a 30-year period and "included below-the-line in

1 subsequent MKEC, Distribution Cooperative and Southern Pioneer rate proceedings.”
2 “Below the line” is a term used in regulatory ratemaking to characterize items that are
3 recorded in an account that is excluded for ratemaking purposes, thereby excluding them
4 from the cost of service to be recovered through charges to ratepayers. However,
5 paragraph 21 further states that:

6 Notwithstanding, the signatories agree that in subsequent retail
7 rate cases(s) filed after the Effective Date by MKEC, Distribution
8 Cooperatives(s) or Southern Pioneer, the determination of the total
9 revenue requirement shall be sufficient to take into consideration
10 generally acceptable financial covenants, debt costs and acceptable
11 levels of equity and cash reserves of MKEC, the Distribution
12 Cooperative(s) or Southern Pioneer, as the case may be. Hereafter,
13 estimated savings associated with this transaction shall not be
14 subject to review in subsequent rate case(s) filed by MKEC,
15 Distribution Cooperative(s) or Southern Pioneer.”⁽²⁾

16 Under the Stipulation and Agreement, the costs directly related to the acquisition
17 premium are not to be included in the revenue requirement for recovery in rates.
18 However, in order to meet generally acceptable financial covenants as contemplated in
19 this agreement, Mid-Kansas must provide adequate debt service coverage by generating
20 sufficient margins. To the extent the Aquila acquisition premium was financed with debt,
21 any premium paid to acquire the Aquila properties requires additional debt service costs
22 (*i.e.*, additional principal payments and interest expense). These additional costs must be
23 recovered from Southern Pioneer’s customers in the form of electric revenues in order for
24 Southern Pioneer to meet its financial obligations.

25 **E. ADVERSE IMPLICATIONS OF MKEC SPIN-DOWN OF**
26 **SUBTRANSMISSION ASSETS TO SOUTHERN PIONEER**

27 **Q. Did Southern Pioneer acquire its Aquila assets directly from Aquila?**

² *MKEC Aquila Acquisition*, Docket No. 06-MKEE-524-ACQ, *Stipulation & Agreement*, January 10, 2007, ¶ 21.

1 A. No. MKEC initially acquired all of Aquila's Kansas Electric assets. MKEC then
2 spun down to Southern Pioneer certain sub-transmission, distribution and general plant
3 assets to Southern Pioneer which MKEC had acquired from Aquila.

4 **Q. Did MKEC retain ownership of certain of the assets acquired from Aquila?**

5 A. Yes. MKEC retained ownership of certain generation, transmission and general
6 plant assets acquired from Aquila.

7 **Q. What is Southern Pioneer's target DSC?**

8 A. Southern Pioneer's target DSC is 2.0 (Macke Direct, p. 23, ll. 16-22) with a
9 proposed phase-in to achieve that target (*id.*). Under Southern Pioneer's proposed DSC
10 Plan, there would be a DSC target each year for 2012-2015 that would allow rates to
11 ramp up to ultimately produce the 2.0 in 2015. (Macke Direct, p. 27, ll. 10-19.)

12 **Q. Had MKEC not spun down the ownership of sub-transmission facilities to
13 Southern Pioneer, but instead had retained ownership of those facilities for
14 ratemaking purposes, what would have been the target DSC for MKEC?**

15 A. MKEC recently submitted a proposed formula-based rate for recovery of
16 transmission costs in Docket No. 12-MKEE-650-TAR. As part of that rate change
17 application, MKEC is requesting a DSC ratio of 1.3104, which "includes the equivalent
18 of 0.5% incentive adder on return on equity (ROE), consistent with the ROE adder that
19 FERC has approved for every FERC-regulated TO operating in Kansas, as an incentive
20 for participation in SPP" (Application, p. 4). MKEC is also seeking a Margins for
21 Interest ("MFI") of 1.5715, which likewise includes such incentive adder effect (*id.*).

22 **Q. Why are MKEC's target DSC and MFI relevant and significant in the
23 context of Southern Pioneer's revenue requirements?**

1 A. Had MKEC retained ownership of the sub-transmission facilities that were spun
2 down to Southern Pioneer, it is obvious that MKEC would be seeking revenues
3 associated with those facilities that are based upon lower DSC and MFI financial metrics
4 than the target 2.0 DSC which is being sought for Southern Pioneer. The spin down of
5 these sub-transmission assets, therefore, results in higher revenue requirements for the
6 sub-transmission facilities than would have been required with continued MKEC
7 ownership. This factor is illustrative of yet another decision with regard to the
8 structuring of Southern Pioneer that has an adverse effect upon its customers. In
9 addition, the higher margins (or profits) collected by Southern Pioneer to attain a 2.0
10 DSC, as compared to the lower MKEC DSC, will create additional equity capital in
11 Southern Pioneer for which the sole beneficiary is Pioneer and also will require an
12 increased income tax expense component that would not be required by MKEC.
13 Southern Pioneer's customers will have no claim on those higher margins since Southern
14 Pioneer is not a cooperative.

15 **Q. Is Southern Pioneer's long-term target of a 2.0 DSC the CoBank minimum**
16 **DSC requirement?**

17 A. No. If Southern Pioneer's DSC Plan is not approved, CoBank's standard
18 minimum DSC requirement of 1.35 will apply. (*Id.*, p. 19, l. 14 – p. 20, l. 3.) If Southern
19 Pioneer's proposed DSC Plan were approved, CoBank's minimum required DSC would
20 begin at 1.0 for 2012 and ramp up to 1.5 starting in 2016 (*id.*, p. 20, ll. 4-15) and
21 presumably remain at the 1.5 level beyond 2016.

22 **Q. How does Southern Pioneer's proposed target 2.0 DSC compare with typical**
23 **DSC's maintained by electric cooperatives?**

1 A. As noted by Mr. Macke, on behalf of MKEC and Southern Pioneer, the National
2 Rural Utilities Cooperative Finance Corporation (“CFC”) Key Ratios Trend Analysis
3 shows that nationally for 2006-2010, the average DSC was 1.88 and for Kansas was 1.83.
4 (*Id.*, p. 21, ll. 1-8.) Clearly, Southern Pioneer is asking the Commission to approve a
5 DSC that exceeds both the national average and the Kansas average that is typically
6 maintained for electric cooperatives.

7 **Q. Is Southern Pioneer obligated to meet any other financial metrics as part of**
8 **its CoBank loan covenants?**

9 A. Yes. Southern Pioneer is obligated to achieve certain equity to total assets ratios.
10 These minimum equity to total assets ratios start at zero (0) through mid-2013 and
11 increase to 11% as of the first quarter of 2019.

12 **Q. If Southern Pioneer’s DSC Plan is approved, will Southern Pioneer meet its**
13 **minimum equity to total assets ratio obligations?**

14 A. Yes. In fact, Southern Pioneer acknowledges that under its DSC Plan it will
15 substantially exceed the CoBank minimum equity to total assets ratios. By year-end
16 2016, Southern Pioneer will have achieved a projected equity position of 18% as
17 compared to the CoBank minimum for that year of only 5%. (*Id.*, p. 33, ll. 4-9.)

18 **F. CONCLUSIONS AND RECOMMENDATIONS REGARDING**
19 **BALANCING THE RESPECTIVE INTERESTS OF SOUTHERN**
20 **PIONEER AND ITS CUSTOMERS**

21 **Q. What do you conclude regarding the various business structure and**
22 **financing decisions adopted by Southern Pioneer which you have just described?**

1 A. From the outset of the formation of Southern Pioneer, it has made structural and
2 financial decisions which have adversely impacted its customers. Such adverse effects
3 manifest themselves in higher rates to the customers.

4 Southern Pioneer chose a for-profit, taxable structure, which has led to increased
5 rates due to the necessity to collect a component of costs for imputed income taxes.
6 Southern Pioneer chose a C-corporation business structure, which results in all equity
7 earnings accruing to the benefit of the sole stockholder, Pioneer. This contrasts sharply
8 with a cooperative structure where the equity interest created through rates would accrue
9 to the members/ratepayers. Under the cooperative structure, the members/ratepayers
10 ultimately would receive patronage capital assignments and eventual refunds. Southern
11 Pioneer's customers, however, will not.

12 MKEC is the applicant in this proceeding. The proposed rates are for MKEC's
13 Southern Pioneer Division. Consistent with the Stipulation and Agreement in Docket
14 524, MKEC's rates should not include an income tax expense component as part of the
15 revenue requirements. Consistent with this commitment, the income tax expense
16 component should be excluded from MKEC's Southern Pioneer Division revenue
17 requirements.

18 Southern Pioneer refinanced its lower-cost FFB debt with higher-cost CoBank
19 financing. As part of that refinancing, Southern Pioneer incurred and had to finance a
20 FFB prepayment penalty of approximately \$9.7 million. The higher cost of CoBank
21 financing, including the cost of the FFB prepayment penalty, would be recovered in
22 Southern Pioneer's proposed rates.

1 As part of Southern Pioneer's acquisition of assets, it incurred an acquisition
2 premium of about \$22.10 million which, likewise, is being financed with higher cost
3 CoBank debt and the cost of such acquisition premium, including financing costs, is
4 being recovered in Southern Pioneer's rates.

5 The decision by MKEC and Southern Pioneer to spin down the ownership of sub-
6 transmission facilities from MKEC to Southern Pioneer also causes Southern Pioneer's
7 customers to incur higher costs due to the imposition of a higher DSC and related income
8 tax expense component by Southern Pioneer than the target DSC of MKEC and no
9 income tax expense component had MKEC retained ownership of such sub-transmission
10 assets. This structural decision, likewise, has led to higher revenue requirements and,
11 hence, higher rates for Southern Pioneer's customers.

12 **Q. Should the Commission consider all of these structural and financial**
13 **decisions by Southern Pioneer in its determination of just and reasonable rates?**

14 A. Yes. The regulatory process establishes a balance between the respective interests
15 of the regulated utility and its customers. Absent a definitive showing that Southern
16 Pioneer's acquisition of the facilities which constitute its system have produced
17 quantifiable benefits that substantially offset the adverse effects of these structural and
18 financial decisions, it is imperative that the Commission protect the customers from the
19 excessive revenue requirements effects of these decisions.

20 **Q. How do you recommend that the Commission take into account Southern**
21 **Pioneer's structural and financing decisions in balancing the respective interests of**
22 **Southern Pioneer and its customers in setting Southern Pioneer's rates?**

1 A. Even if the Commission does not make any of the adjustments discussed above,
2 Southern Pioneer's rates should be set based upon the most stringent of the financial
3 metrics which it is required to achieve under its CoBank loan covenants – either the
4 specified minimum required DSC or the specified equity to total assets ratio. The
5 revenue requirements should be based upon the minimum DSC requirement of 1.35 to
6 achieve the minimum equity total assets ratio requirements. In other words, if a higher
7 DSC than the minimum in a given year is required to achieve the equity to total assets
8 ratio, the latter metric would be the most stringent and, therefore, the one to be used in
9 setting Southern Pioneer's revenue requirement. If, going forward, Southern Pioneer can
10 demonstrate that a higher DSC, or higher equity to total assets ratio, than the minimum
11 CoBank loan covenant requirements but less than its 2.0 target DSC would reduce
12 Southern Pioneer's revenue requirements by an amount that offsets the adverse effects of
13 the structural and financing decisions which I have previously described, the Commission
14 should revisit these matters in future rate proceedings.

15 IV. REASONABLENESS OF SOUTHERN
16 PIONEER'S PROPOSED DSC PLAN

17 **Q. Briefly describe the DSC Plan proposed by MKEC and Southern Pioneer**
18 **(Exhibit RJM-8).**

19 A. The proposed DSC Plan essentially would allow adjustment of Southern Pioneer's
20 rates each year to achieve a target DSC. Mr. Macke, on behalf of MKEC and Southern
21 Pioneer, describes in detail the functioning of the proposed DSC Plan (Macke Direct, p.
22 23, l. 16 – p. 25, l. 2).

23 **Q. Is the proposed DSC Plan cost-of-service based?**

1 A. No. Southern Pioneer's rates would be established in this proceeding based upon
2 cost-of-service analyses. This is typical with regard to the establishment of regulated
3 rates for entities such as Southern Pioneer. Going forward, however, under the DSC Plan
4 these rates would be adjusted based upon a per-kWh charge that is derived based solely
5 upon whether the Southern Pioneer system achieved the target DSC and without
6 consideration as to the performance by individual rate classes in achieving the target
7 DSC. The net result of this process is the automatic adjustment of every Southern
8 Pioneer rate in the future without any requirement to demonstrate how individual rates
9 performed with regard to the target DSC from year to year.

10 **Q. Would the proposed DSC Plan apply to Schedule LAC?**

11 A. Yes (Exhibit SPD-2, p. 29).

12 **Q. Should Southern Pioneer be authorized to implement its proposed DSC
13 Plan?**

14 A. No.

15 **Q. Please explain why not.**

16 A. While the DSC Plan functions on a cost basis for the total Southern Pioneer
17 system and revenue requirement, it is not cost-based with regard to charges pursuant to
18 its various rate schedules. Individual rates should be based upon allocated costs. Using a
19 generically applied system-wide cost adjustment such as under the proposed DSC Plan
20 fails to take into account allocated costs and the performance of individual rates with
21 regard to achievement of the target DSC. Given that Southern Pioneer would utilize this
22 automatically adjusting DSC Plan for an indeterminate number of years into the future,

1 the rote application of an adjustment factor to all rate schedules over time may not track
2 the actual allocated costs, including DSC, on an individual rate schedule basis.

3 Such annual adjustment of all rate schedules on a per-kWh basis should not be
4 allowed to substitute for the periodic establishment of cost-based rates based upon fully
5 allocated cost-of-service studies such as has been filed in this proceeding.

6 While the potential saving of some regulatory expense by avoiding such studies
7 and relying on the DSC Plan may have some superficial appeal, Southern Pioneer, as a
8 regulated, taxable entity, should not be permitted to avoid the periodic adjustment of its
9 filed rates based upon fully-allocated cost-of-service analyses. Requiring such periodic
10 cost-based adjustments is especially important in light of the divergence of the respective
11 interests of Southern Pioneer and its customers that I described earlier.

12 **Q. Are there any other reasons why the proposed DSC Plan should be rejected?**

13 A. Yes. There are a number of other serious flaws in the proposed DSC Plan. One,
14 the periodic rate adjustment under the proposed DSC Plan is calculated on a per-kWh
15 basis. Debt service coverage is related to capital investment; therefore, it is a fixed-cost
16 related component of the cost of providing service. Utilizing a per-kWh adjustment
17 factor would be inconsistent with the basis for determining the appropriate revenue
18 requirement based upon DSC in a properly developed cost-of-service analysis. This
19 disconnect reflects yet another flaw that could result in improper charges among the rate
20 classes.

21 Two, the proposed Filing Review and Approval provisions of the proposed DSC
22 Plan (*id.*, p. 4) are directed solely at a review of the periodic application “to determine if
23 it is in compliance with the Plan as approved by the Commission, or to obtain compliance

1 from Southern Pioneer if Staff believes the initial filing contains errors” (*id.*). This very
2 narrow review precludes investigation of the reasonableness of Southern Pioneer’s
3 underlying investments and expenses as they change from time to time. Essentially, the
4 DSC Plan would function as a cost-of-doing business adjustment factor without review as
5 to the prudence, justness and reasonableness of the underlying costs for which MKEC
6 and Southern Pioneer seek recovery. Such automatic recovery without regard to the
7 justness, reasonableness and prudence of underpinning costs is totally contrary to the
8 tenet of establishing cost-of-service based rates for regulated entities, with all the
9 attendant procedures for review of the costs for which rate recovery is sought.

10 Three, the Filing Review and Approval procedures would be restricted to KCC
11 Staff. Only if the KCC Staff filed an objection with the Commission would there
12 potentially be a proceeding in which interested parties, such as Southern Pioneer’s
13 customers, would be allowed to participate. Precluding customer participation in the
14 Filing Review and Approval process is blatantly unjust and unreasonable, given the
15 customers are directly affected by the implementation of the DSC Plan. It is clear that
16 the only recourse for customers that have “questions, concerns or complaints regarding
17 Southern Pioneer or its parent that are outside the scope of the DSC ratemaking” shall not
18 raise such matters “in the annual adjustment dockets” (*id.*). Customers would have to
19 “[raise] such issues through the normal means available before the KCC” (*id.*). These
20 requirements totally shift the burden with regard to establishment of just and reasonable
21 rates. Rather than MKEC and Southern Pioneer having to withstand the scrutiny of a
22 normal rate case to adjust rates, they would be allowed to automatically recover whatever
23 costs are incurred, including achievement of the target DSC under the DSC Plan. If,

1 however, customers were concerned that either overall costs were questionable or that the
2 DSC Plan was not accurately tracking the allocated costs of providing service to
3 individual customer classes, the customers would have to seek redress through some form
4 of formal complaint with the Commission. Given that Southern Pioneer is the repository
5 for all information required to prepare cost-of-service studies, this reversal of the burden
6 of establishing just and reasonable rates places a near insurmountable burden on
7 customers because they would have an extremely limited ability to challenge Southern
8 Pioneer's costs, cost allocation and rates. The resulting shift of this burden from a
9 ratemaking perspective from the regulated utility to the customers is unwarranted,
10 constitutes bad policy, and should be rejected.

11 **Q. If, notwithstanding your recommendation to the contrary, the Commission**
12 **approved the use of the DSC Plan proposed by MKEC Southern Pioneer, should**
13 **that DSC Plan be approved without modification?**

14 A. No. The DSC Plan as filed is flawed. The Commission should require a number
15 of modifications before it is permitted to go into effect.

16 **Q. Please describe the necessary modifications.**

17 A. At a minimum, the Commission should require the following modifications to the
18 proposed DSC Plan to balance the competing interests of Southern Pioneer and its
19 customers.

- 20
- 21 • The DSC Plan, rather than being "evergreen" should have a finite period (*e.g.*,
22 no more than four years) of applicability subsequent to which Southern
23 Pioneer should be required to make a complete, cost-based rate filing to
rebase its individual rates.
 - 24 • The annual adjustments should be calculated on a \$/kW basis to reflect the
25 fact that the DSC is fixed-cost related.

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the Application of)
Mid-Kansas Electric Company, LLC)
for Approval to Make Certain Changes) Docket No. 12-MKEE-380-RTS
in its Charges for Electric Service in the)
Geographic Service Territory Served by)
Southern Pioneer Electric Company.)

AFFIDAVIT

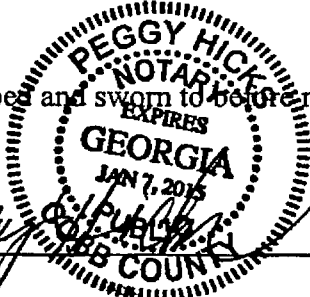
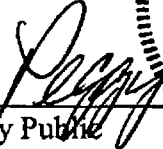
STATE OF GEORGIA)
) SS:
COUNTY OF COBB)

I, Stephen Page Daniel, being duly sworn, certify that the attached pre-filed direct testimony and exhibits in this docket were prepared by me or under my supervision and that the answers contained in such testimony and exhibits are true and correct to the best of my knowledge, information and belief.



Stephen Page Daniel

Subscriber and sworn to before me this 18th day of April, 2012.

Notary Public

Resume of Stephen Page Daniel

EDUCATION: Master of Business Administration in Finance, Georgia State University (1978)
Bachelor of Industrial Engineering, Georgia Institute of Technology (1970)

PROFESSIONAL MEMBERSHIP: Institute of Electrical and Electronics Engineers

EXPERIENCE:

7/10-Present Executive Consultant, GDS Associates, Inc.

2/86-6/10 Founding Principal of GDS Associates, Inc.

2/86-11/06 Executive Vice President of GDS Associates, Inc.

1/71-2/86 Mr. Daniel served as rate analyst (1971-1974), project manager (1975-1981), Group Manager - Rate and Analytical Services (1982-1984), and Assistant Vice President - Rate and Analytical Services (1985-1986) with Southern Engineering Company. Mr. Daniel was also Coordinator - Load and Energy Management Services from 1978 to 1981.

During his forty-two (42) years' experience in the electric utility industry, Mr. Daniel has consulted with utilities, government agencies, and industrial clients in forty-one (41) states in the following areas:

- Policy evaluations regarding electric industry restructuring and retail competition.
 - > Mergers and Acquisitions, including market power related issues.
 - > Power supply planning for generation and transmission utility systems and distribution systems.
 - Negotiation of purchased power contracts.
 - Negotiation of joint ownership and operating agreements.
 - Development of and evaluation of responses to power supply RFPs.
 - Damage assessments.
 - > Transmission and Ancillary Services access/pricing issues:
 - Negotiation of transmission arrangements (including OATT service)
 - Policy advocacy/rulemaking, including RTO development
 - Open-access transmission implementation/compliance
 - Transmission rate case litigation
 - Strategic Planning
 - > Negotiation of wholesale (sales-for-resale) power supply contracts on behalf of cooperative and municipal electric power systems involving:
 - Full and partial requirements services
 - Interchange services
 - Generation support services
 - Joint ownership arrangements
 - > Preparation of pooling rates for cooperative generation and transmission systems.
 - > Preparation of financial forecasts and forecasts of operations for rural electric distribution and generation and transmission systems.

- > Preparation of cost-of-service studies and sales-for-resale rate studies for cooperative generation and transmission systems.
- > Preparation of retail rate studies and cost-of-service studies for rural electric distribution systems and municipal electric systems.
- > Analysis of cost-of-service studies filed by others with the Federal Energy Regulatory Commission (formerly Federal Power Commission) and various state regulatory commissions.
- > Preparation of revenue requirements studies for cooperative and municipal power systems.
- > Facilities valuation studies for property sales and condemnations.
- > Assignments in specialized areas of:
 - Industry Restructuring/Wholesale Competition/Retail Competition
 - Rate design for special loads
 - Financial requirements analyses
 - Evaluation of financing alternatives
 - Acquisition, merger and divestiture evaluations
 - Regulatory rulemaking
 - Public Utility Regulatory Policies Act of 1978
 - Cogeneration and Small Power Production
 - Territorial Integrity

REGULATORY EXPERIENCE:

Federal Energy Regulatory Commission (formerly Federal Power Commission) ^{1/}
Alabama Public Service Commission ^{3/}
Alaska Public Utilities Commission ^{1/}
Arizona Corporation Commission ^{1/}
Arkansas Public Service Commission
Public Utilities Commission of the State of Colorado
Florida Public Service Commission ^{2/}
Georgia Public Service Commission
Indiana Regulatory Commission (formerly Public Service Commission of Indiana)
Kansas Corporation Commission
Louisiana Public Service Commission
Michigan Public Service Commission
Mississippi Public Service Commission ^{2/ 3/}
Public Utility Commission of Nevada
North Carolina Utilities Commission
Pennsylvania Public Utility Commission
South Carolina Public Service Commission
Texas Public Utility Commission ^{1/}
Utah Public Service Commission
Virginia State Corporation Commission
West Virginia Public Service Commission ^{2/}

^{1/} Including Regulatory Rulemaking
^{2/} Including Generic Hearings
^{3/} Including Restructuring and Deregulation Proceedings

EXPERT TESTIMONY IN COURT PROCEEDINGS:

- (1) Clay County Superior Court, Clay County, Florida
- (2) United States Federal District Court, District of Nebraska
- (3) United States Federal District Court, Anderson, South Carolina
- (4) United States Bankruptcy Court, Opelousas, Louisiana
- (5) United States District Court, Middle District Of Tennessee, Northeastern Division

AFFIDAVITS IN COURT PROCEEDINGS:

- (1) United States Federal District Court, Middle District – Alabama, Northern Division
- (2) Supreme Court of New York, Niagara County, Index No. 081556, Judge Joslin, Affidavit in Appellate Proceeding

OTHER EXPERT APPEARANCES:

- (1) Kansas Legislature Electric Industry Restructuring Task Force
- (2) FERC PL04-9 Technical Conference on Acquisition and Disposition of Merchant Generation Assets by Public Utilities

PUBLICATIONS

- “Joint Ownership of Transmission” - CFC Power Review - Spring 1989 (with Robert M. Gross)
“Long-Term Transmission Access Strategy - Do You Have One?” – TransActions, Vol. No. 198, January 1998
“Part I: Wholesale Formula Rates: Boon or Bane?” – TransActions, Vol. No. 108, June 2008
“Part II: Wholesale Formula Rates: Boon or Bane?” – TransActions, Vol. No. 208, November 2008

LECTURES/SEMINARS:

- Retail Competition/Restructuring: Framing the Debate
Florida Utility Industry Restructuring Task Force, June 9, 1998
- NRECA Restructuring Forum
Technical Advisor to Roundtable Discussion (January 28, 1998)
- Missouri Retail Competition
Missouri REC Managers' Conference, June 5, 1997
- Southeast Power Markets Outlook
Southeast Power Markets, Atlanta, GA, May 21, 1997
- Open-Access Transmission: A Key to Competitive Bulk Power Markets
1996 Strategic Planning Program, Strategic Planning Process for 1997 and Beyond, Alabama Electric Cooperative, Inc., July 2, 1996
- Open-Access Transmission: A Key to Competitive Bulk Power Markets
1996 Annual Engineers Conference
Florida Electric Cooperatives Association, May 15, 1996
- The Future: Transmission Open-Access Update; Industry Restructuring; and Strategic Planning
SMEPA Board of Trustees Forum (1996)
Open-Access Transmission -- The Path to Competitive Bulk Power Markets
- Status of Utility Restructuring in the U.S. and Implications for Georgia
Georgia Public Service Commission Staff Meeting, December 18, 1995
- Unbundling Services and Rates: A Choice or a Necessity?
Public Power: Preparing for Competition
Infocast, Washington, D.C., November 17, 1995

- Trends in Power Supply: What's All the Change About?
The FERC MEGA-NOPR, Privatization & Regulatory Jurisdictional Issues
15th Annual Southeastern Electric & Natural Gas Conference, October 10, 1995
- Transmission Access: The Path to Competition
The Electric Cooperatives of South Carolina, Engineering & Purchasing Association Meeting, May 1995
- Transmission Access: The Path to Competition
SMEPA Board of Trustees Forum (1994)
- The Changing Structure of Electric Utilities
G&T Accounting and Finance Association 1994 Annual Meeting
- Surviving and Thriving as Rural (Cooperative) Energy Systems in the 90's and Beyond.
Southeastern Power Administration Integrated Resource Planning Conference (1993)
- Transmission Access and Pricing Policies of the FERC
National G&T Managers Association Meeting (1993)
- G&T Rate Theory: Competitive Positioning
NRECA G&T Rate Seminar (1993)
- Transmission Strategies In A Changing Regulatory And Access Environment
Electric Systems Planning and Operations Conference (1992)
- A Wholesale Rate Case: The Consultant's Role
Seminole Electric Cooperative, Inc., June 1992 Employee Meeting
- The Economic Impact of Annexation On Rural Electric Systems: The Technical Perspective: and Price Alone May Not Be Good Enough! (Workshop)
NRECA Territorial Integrity Conference (1990)
- Regulation After Refunding: Life At The FERC
National G&T Managers Association Meeting (1989)
- Joint Ownership: A Transmission Access Alternative
Executive Enterprises Third Annual Transmission Access And Pricing Conference (1989)
- FERC, IPPS, Etc.
NRECA Transmission Forum (1989)
- FERC Regulation of G&Ts: Prospect and Impact
NRECA G&T Legal Seminar (1989)
- A Review of Reality -- Cooperative/Creative Ratemaking
NRECA 1985 Directors' Update (1985)
- Electric Rates: The Impact on Load and Energy Management
NRECA Load Management Workshop (1980)
- AEPCO Rates: Past, Present & Future
Grand Canyon State Electric Cooperative, Inc. Annual Meeting (1979)
- Fuel Adjustment Clauses and Rates
Georgia Rural Electric Managers Association (1979)
- How to Distribute the Benefits of Load Management
NRECA Load Management Conference (1979)
- Fuel Adjustments and Power Rates
South Carolina Electric Cooperative Managers Association (1979)
- Load Management and Rates
Indiana Statewide REC, Inc. (1978)
- The Philosophy of Setting Rates
Cooperative Power Association (1978)
- Strategies For Load and Energy Management
Northwest Public Power Association 1978 Directors Conference (1978)
- Capital Budgeting to Meet System Planning Needs
APPA Accounting & Finance Workshop (1974)

Supporting Source Documents

KANSAS ELECTRIC POWER COOPERATIVE, INC.
Information Request

Request No.1-9

Company Name MID-KANSAS ELECTRIC COMPANY, LLC
Docket Number 12-MKEE-380-RTS
Request Date February 3, 2012
Date Information Needed February 17, 2012
RE: MKEC's Application of December 20, 2011

Please provide the following:

With reference to the direct testimony of Stuart S. Lowry ("Lowry Direct"), p. 5, ll. 13-18, provide the following:

- a. An unconditional admission that Southern Pioneer's retail customers do not receive patronage capital allocations, dividends or other forms of capital benefits from the operation of Southern Pioneer; and
- b. If the response to subpart a., above, is other than an unconditional admission, a detailed explanation of that response.

Response:

That is correct in that retail customers do not receive patronage capital allocations, dividends or other forms of capital benefits from the operation of Southern Pioneer.

Submitted By KEPCo
Submitted To MKEC

If for some reason, the above information cannot be provided by the date requested, please provide a written explanation of those reasons.

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 KEPCo any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request.

Signed: *Robert S. Medina*

Date: 02/16/2012

KANSAS ELECTRIC POWER COOPERATIVE, INC.
Information Request

Request No.1-10

Company Name MID-KANSAS ELECTRIC COMPANY, LLC
Docket Number 12-MKEE-380-RTS
Request Date February 3, 2012
Date Information Needed February 17, 2012
RE: MKEC's Application of December 20, 2011

Please provide the following:

With reference to the Lowry Direct, p. 5, ll. 13-18, provide the following:

- a. An unconditional admission that Southern Pioneer's LAC customers do not receive patronage capital allocations, dividends or other forms of capital benefits from the operation of Southern Pioneer; and
- b. If the response to subpart a., above, is other than an unconditional admission, a detailed explanation of that response.

Response:

That is correct in that LAC customers do not receive patronage capital allocations, dividends or other forms of capital benefits from the operation of Southern Pioneer.

Submitted By KEPCo

Submitted To MKEC

If for some reason, the above information cannot be provided by the date requested, please provide a written explanation of those reasons.

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 KEPCo any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request.

Signed: 

Date: 02/16/2012

Southern Pioneer New Notes

Note	Commitment	Outstanding	Availability	Maturity	Rate Index	Rate	Rate Maturity
RX0435T3*	\$63,688,239.37	\$63,688,239.37	Close	10/20/2041	FIX	5.37	10/20/2041
RX0435T4	\$30,000,000.00	\$0.00	10/31/2015	10/20/2041	FIX		

* Refinances SoPi FFB notes F0010, F0015, and F0020 and prepayment premium

F0010	\$4,098,464.74
F0015	\$5,365,869.06
F0020	\$44,537,501.73
Premium	\$9,686,403.84
	<u>\$63,688,239.37</u>

Accrued interest advanced of S01	\$148,302.57
	<u>\$148,302.57</u>

Total FFB Payoff **\$63,836,541.94**

May 2011 draw \$21,000,000 Closed 10/14/11 5.37

Total CoBank LT Debt \$84,688,239.37

**Kansas Corporation Commission
Information Request**

Request No: 83

Company Name MID-KANSAS ELECTRIC COMPANY, LLC MKEE
Docket Number 12-MKEE-380-RTS
Request Date January 28, 2012
Date Information Needed February 6, 2012

RE: Other Deductions

Please Provide the Following:

Please provide all supporting workpapers used to calculate the other deductions adjustment totaling \$322,880.

Response: Please reference the spreadsheet provided in response to KCC DR82. This spreadsheet, which was prepared and provided by CoBank, shows a line item for the total prepayment premium of \$9,686,403.84 which Southern Pioneer will amortize in equal installments over the life of the CoBank debt, i.e. 30 years. \$9,686,403.84 divided by 30 years equals \$322,880 per year.

Submitted By Laura Bowman

Submitted To Richard Macke

If for some reason, the above information cannot be provided by the date requested, please provide a written explanation of those reasons.

Verification of Response

I have read the foregoing Information Request and answer(s) thereto and find 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 Commission Staff any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request.

Signed: Rich Macke

Date: 2/3/12

KANSAS ELECTRIC POWER COOPERATIVE, INC.
Information Request

Request No.1-2

Company Name MID-KANSAS ELECTRIC COMPANY, LLC
Docket Number 12-MKEE-380-RTS
Request Date February 3, 2012
Date Information Needed February 17, 2012
RE: MKEC's Application of December 20, 2011

Please provide the following:

With reference to the Scott Direct, p. 4, ll. 11-14, provide the following:

a. Copies of all analyses, financial projections and other information prepared by or on behalf of Southern Pioneer Electric Company ("Southern Pioneer"), Pioneer Electric Cooperative, Inc. ("Pioneer"), or Mid-Kansas Electric Company, LLC ("MKEC") of the financial effects on Southern Pioneer of buying out its Rural Utilities Service ("RUS") debt and refinancing its long-term debt with CoBank or any other financing source, including but not limited to the effects on the following under RUS financing and alternative financing:

- i. Principal payments;
- ii. Interest payments; See attached KEPCO DR2A.
- iii. Debt service payments;
- iv. Interest expense;
- v. Cash flow;
- vi. Revenue requirements;
- vii. Financial ratios;
- viii. Short-term financing requirements before availability of permanent long-term financing; and

b. Copies of all presentations made to the Board of Directors of each entity regarding the subject matter of the subpart a., above, response; and No presentations to MKEC or Pioneer

c. Copies of all other presentations to the Board of Directors of each entity regarding Southern Pioneer buying out its RUS debt and securing alternative long-term debt financing. No other presenters

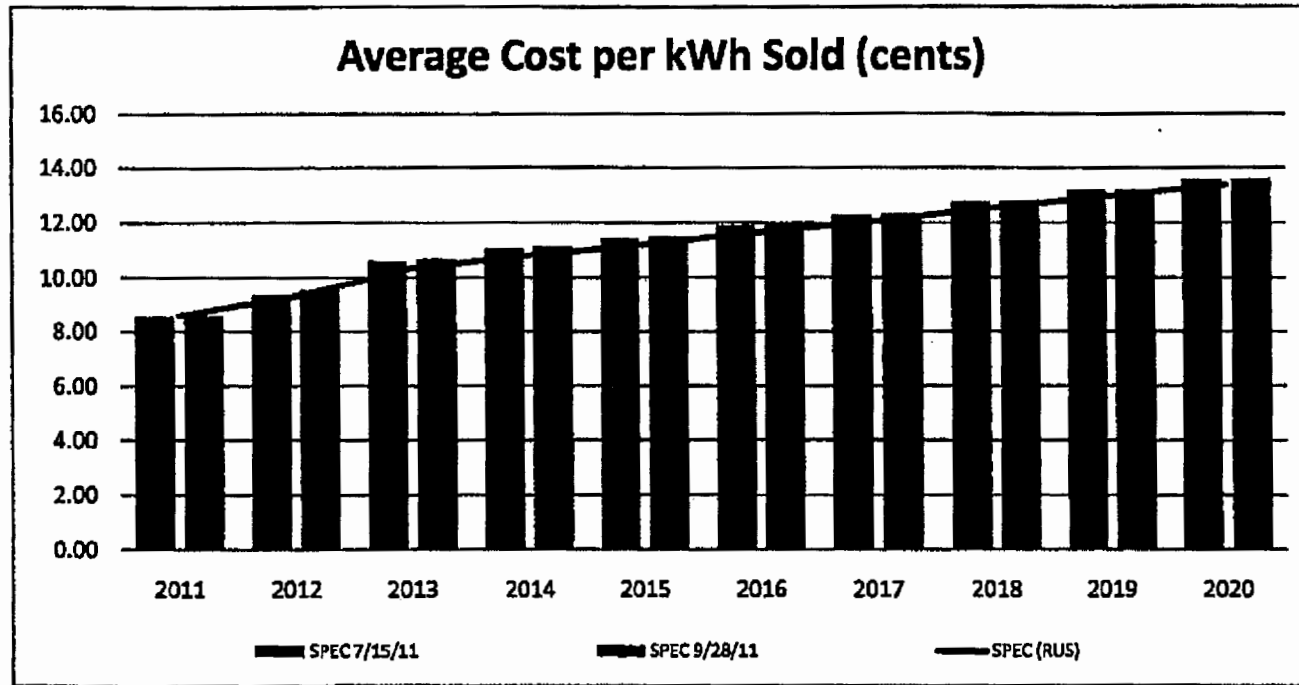
Submitted By KEPCo
Submitted To MKEC

If for some reason, the above information cannot be provided by the date requested, please provide a written explanation of those reasons.

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 KEPCo any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request.

Signed: *Paul S. Magnus*
Date: 02/16/2012

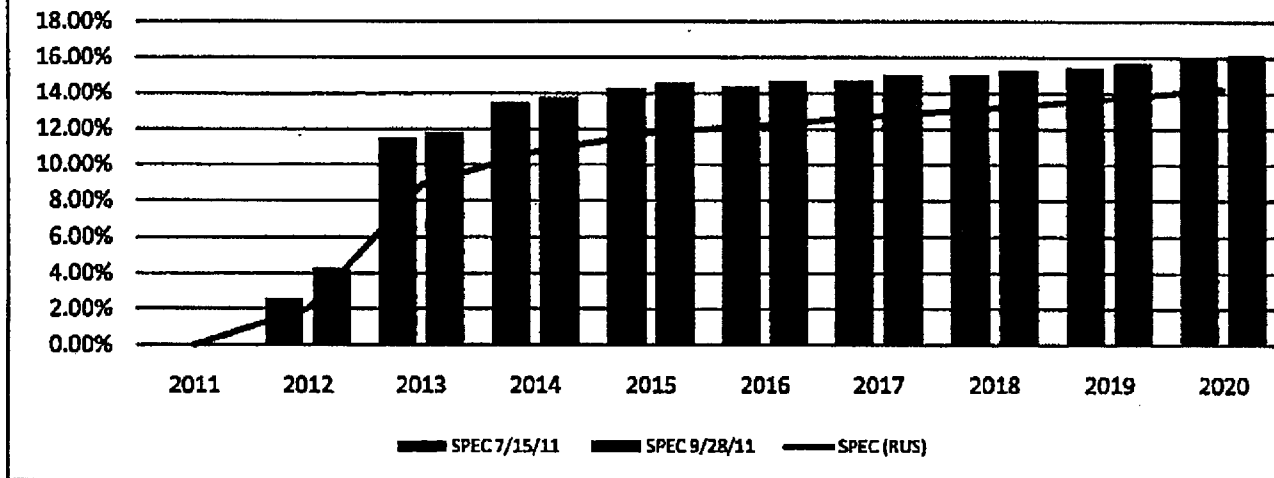


	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SPEC 7/15/11	8.57	9.35	10.60	11.07	11.44	11.87	12.27	12.75	13.16	13.56
SPEC 9/28/11	8.57	9.54	10.67	11.13	11.50	11.92	12.31	12.79	13.19	13.59
SPEC (RUS)	8.57	9.3	10.34	10.8	11.19	11.64	12.04	12.54	12.96	13.37

- * SPEC 7/15/11 - Initial RUS Buyout projection assuming \$ 2.5 million premium
- * SPEC 9/28/11 - Revised RUS Buyout projection assuming \$ 10.5 million premium
- * SPEC (RUS) - Initial Base Case Forecast assuming no RUS Buy Out

- All forecasts identical with the exception of long-term debt. SPEC (RUS) assumes using RUS into the future. SPEC 7/15/11 and SPEC 9/28/11 assume an RUS buyout with different premium amounts paid.

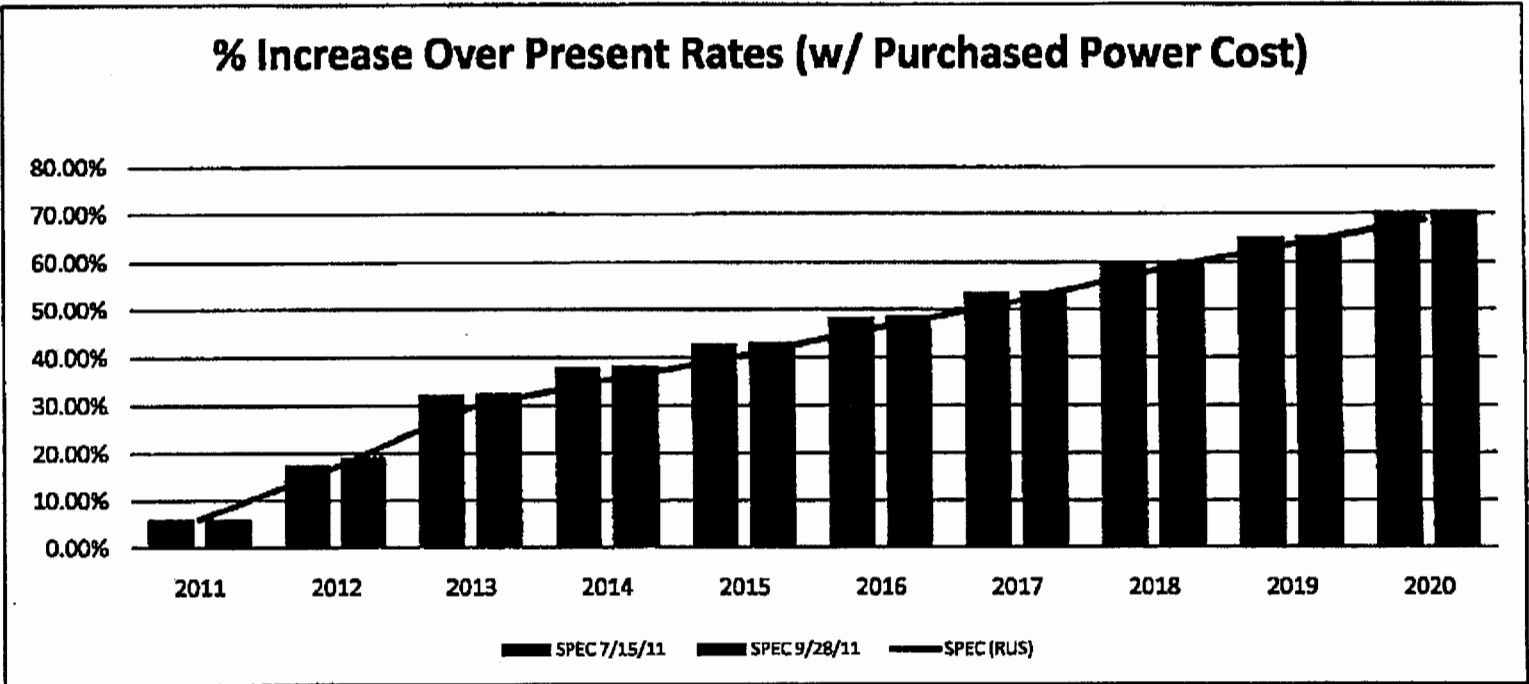
% Increase Over Present Rates (w/o Purchased Power Cost)



SPEC 7/15/11
 SPEC 9/28/11
 SPEC (RUS)

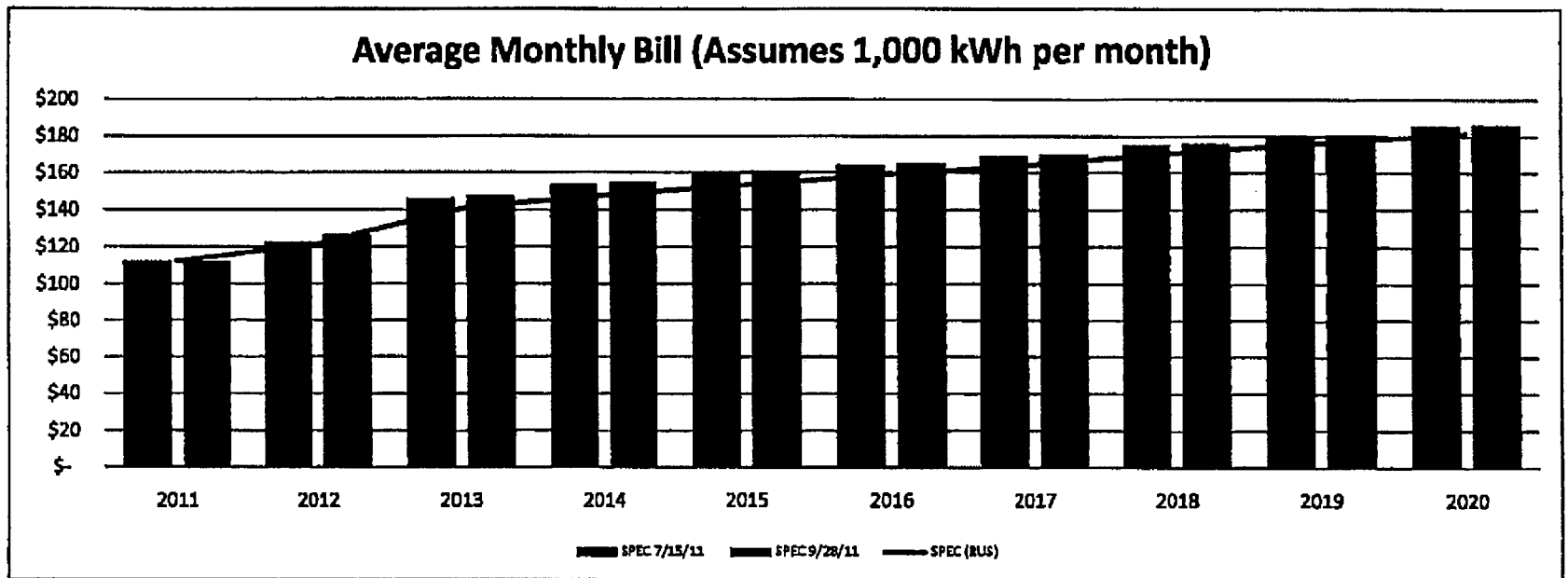
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SPEC 7/15/11	0.00%	2.60%	11.50%	13.44%	14.26%	14.39%	14.74%	15.02%	15.45%	15.92%
SPEC 9/28/11	0.00%	4.32%	11.77%	13.77%	14.63%	14.72%	15.03%	15.28%	15.70%	16.15%
SPEC (RUS)	0.00%	2.03%	8.83%	10.71%	11.77%	12.22%	12.71%	13.13%	13.68%	14.26%

% Increase Over Present Rates (w/ Purchased Power Cost)



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SPEC 7/15/11	6.02%	17.56%	32.29%	38.05%	42.80%	48.50%	53.67%	60.06%	65.35%	70.40%
SPEC 9/28/11	6.02%	19.28%	32.56%	38.38%	43.17%	48.83%	53.96%	60.32%	65.60%	70.63%
SPEC (RUS)	6.02%	16.99%	29.62%	35.32%	40.31%	46.33%	51.64%	58.17%	63.58%	68.74%

SPEC 7/15/11
SPEC 9/28/11
SPEC (RUS)

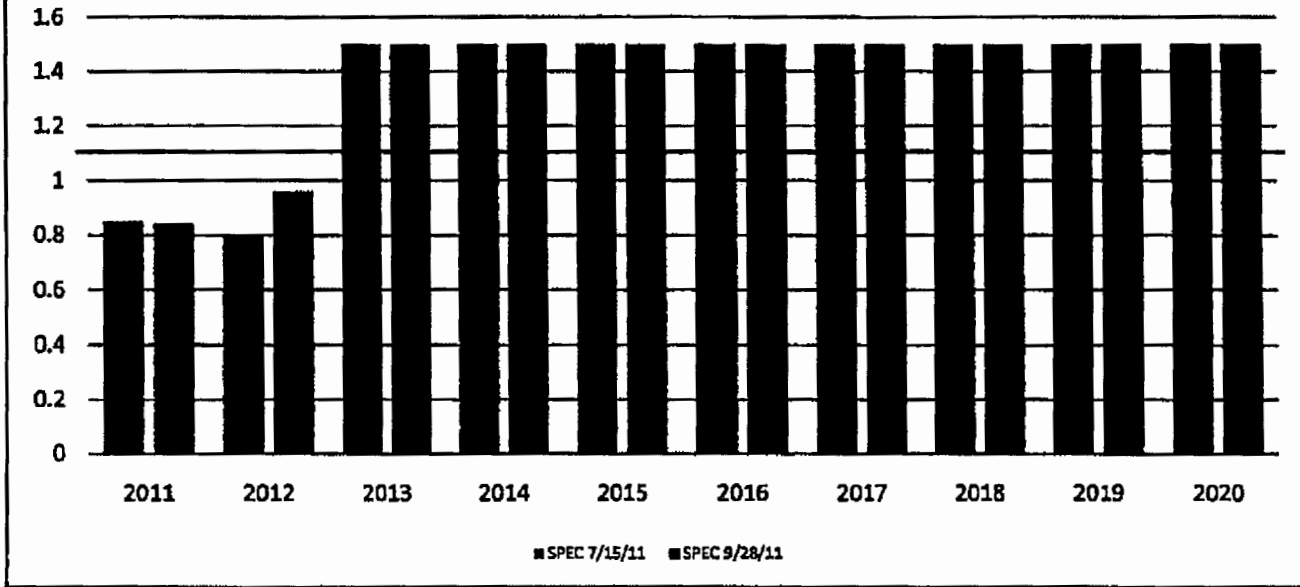


	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SPEC 7/15/11	\$ 112	\$ 123	\$ 146	\$ 154	\$ 159	\$ 164	\$ 169	\$ 175	\$ 180	\$ 186
SPEC 9/28/11	\$ 112	\$ 127	\$ 148	\$ 155	\$ 160	\$ 165	\$ 170	\$ 176	\$ 181	\$ 186
SPEC (RUS)	\$ 112	\$ 122	\$ 140	\$ 148	\$ 153	\$ 159	\$ 164	\$ 170	\$ 176	\$ 181

* Assumes all increases are assigned ~~to~~ on a per kWh basis after removing Industrial Sub-Transmission sales.

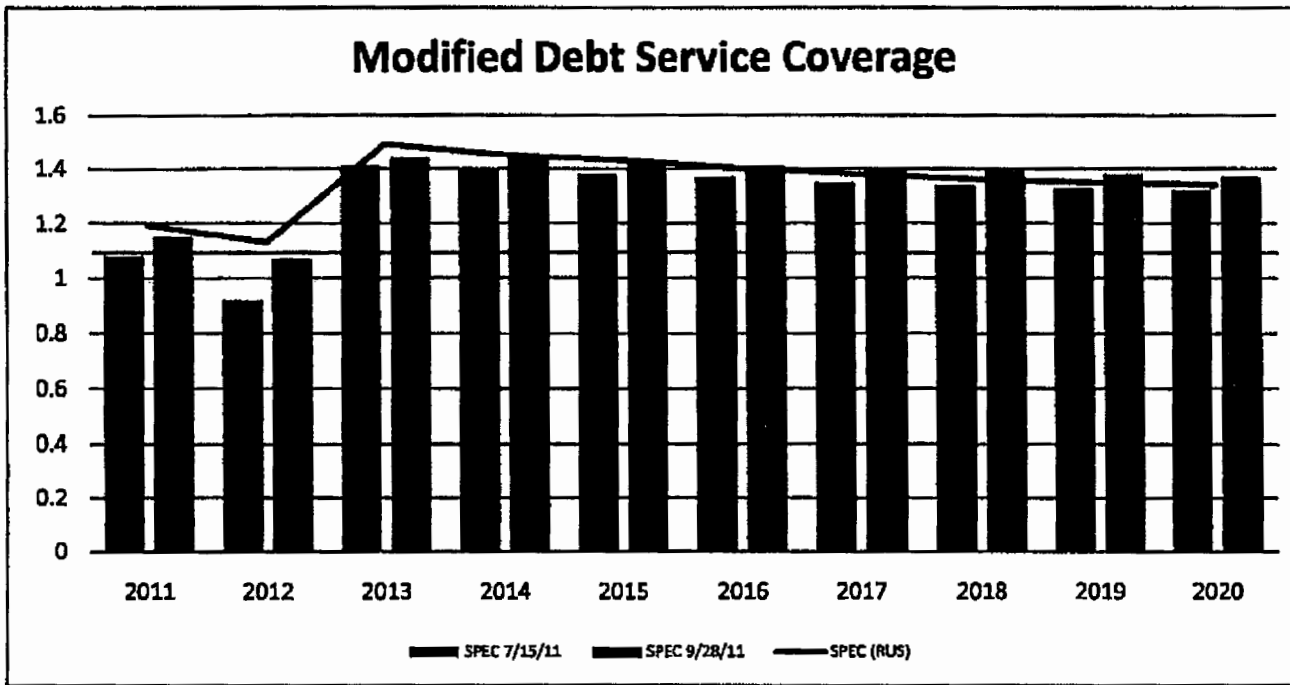
* Attempt at showing average monthly bill to a residential consumer.

Operating Times Interest Earned Ratio



SPEC 7/15/11
SPEC 9/28/11

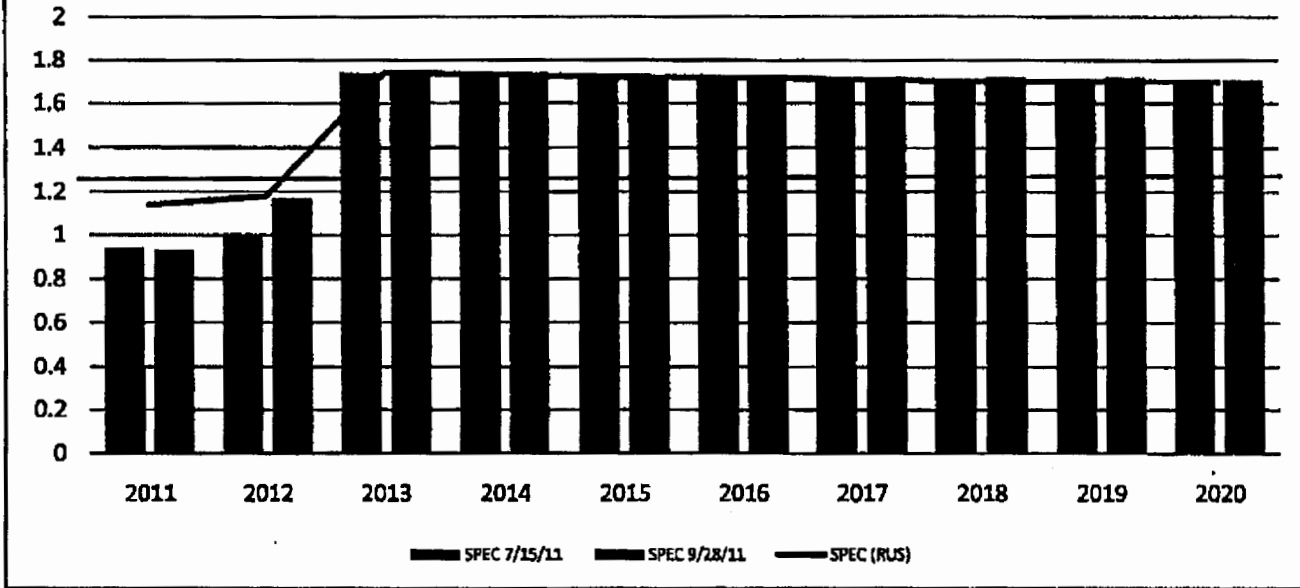
2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
0.85	0.8	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
0.84	0.96	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5



SPEC 7/15/11
SPEC 9/28/11
SPEC (RUS)

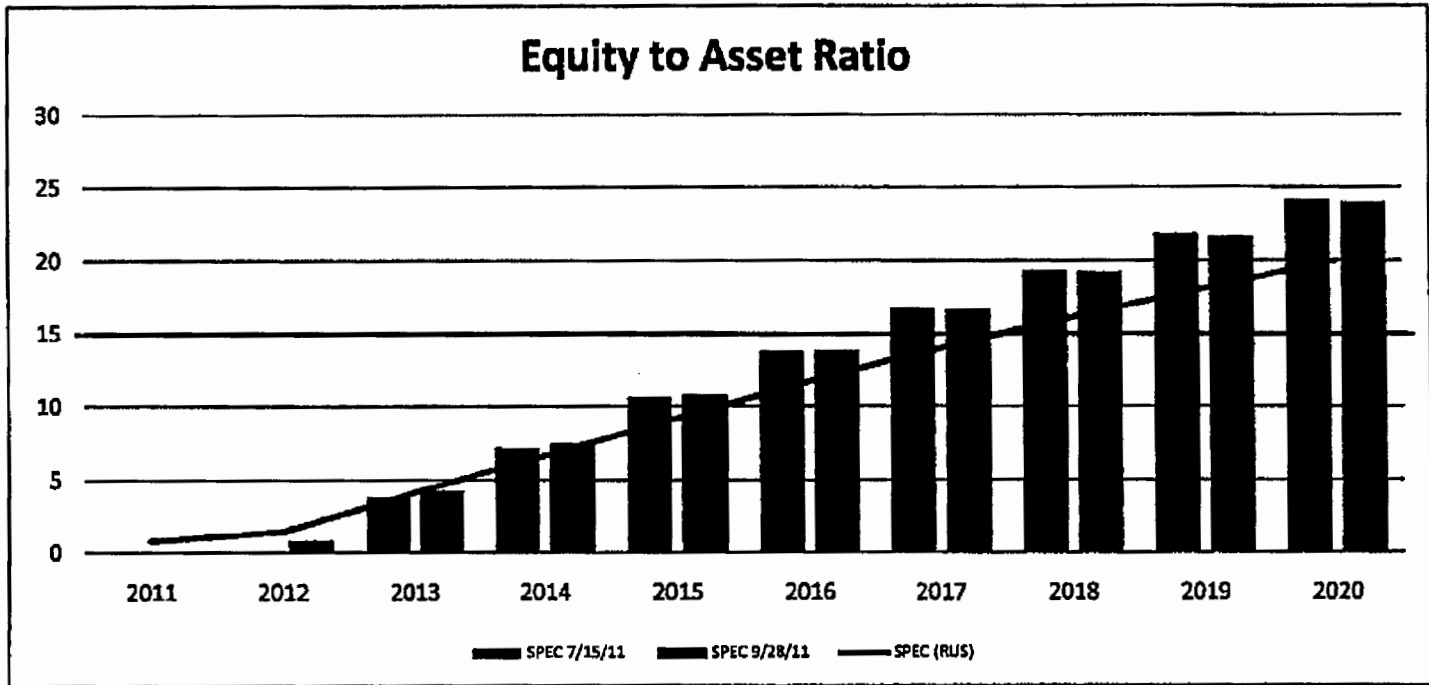
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SPEC 7/15/11	1.08	0.92	1.41	1.4	1.38	1.37	1.35	1.34	1.33	1.32
SPEC 9/28/11	1.15	1.07	1.44	1.44	1.42	1.41	1.4	1.39	1.38	1.37
SPEC (RUS)	1.19	1.13	1.49	1.45	1.43	1.40	1.38	1.36	1.35	1.34

Times Interest Earned Ratio



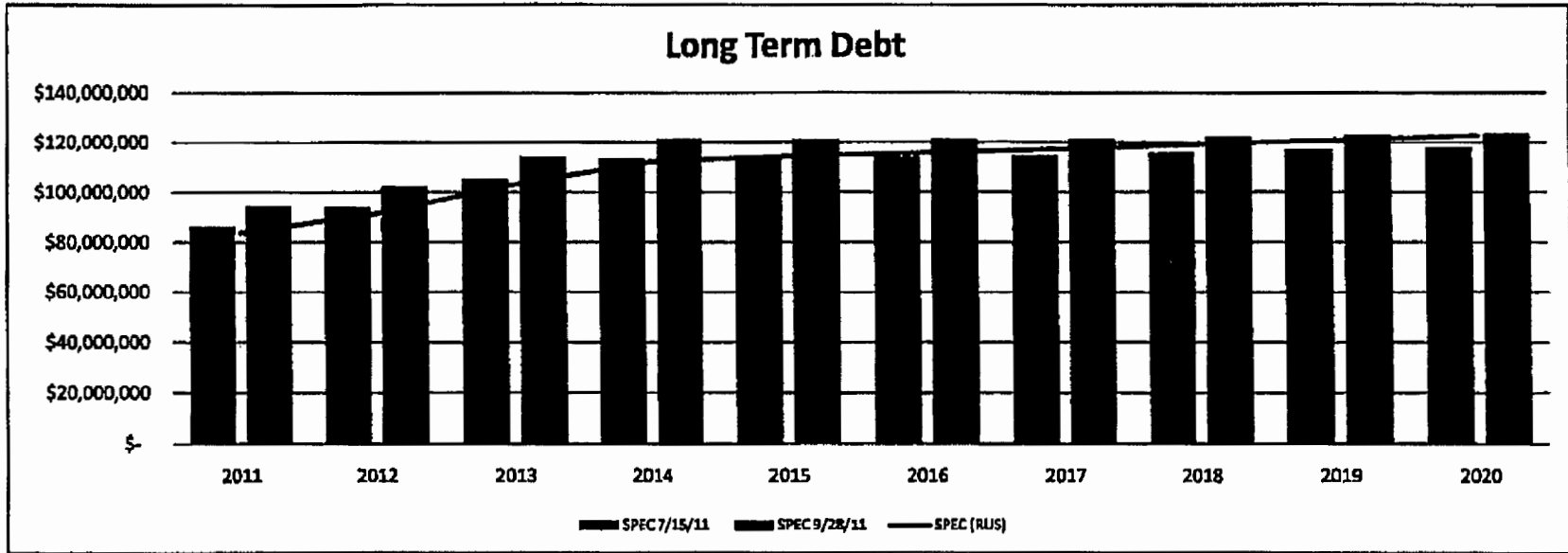
SPEC 7/15/11
SPEC 9/28/11
SPEC (RUS)

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SPEC 7/15/11	0.94	1	1.74	1.74	1.73	1.73	1.72	1.71	1.71	1.71
SPEC 9/28/11	0.93	1.17	1.74	1.74	1.73	1.73	1.72	1.72	1.72	1.71
SPEC (RUS)	1.14	1.18	1.74	1.73	1.72	1.72	1.71	1.70	1.70	1.70

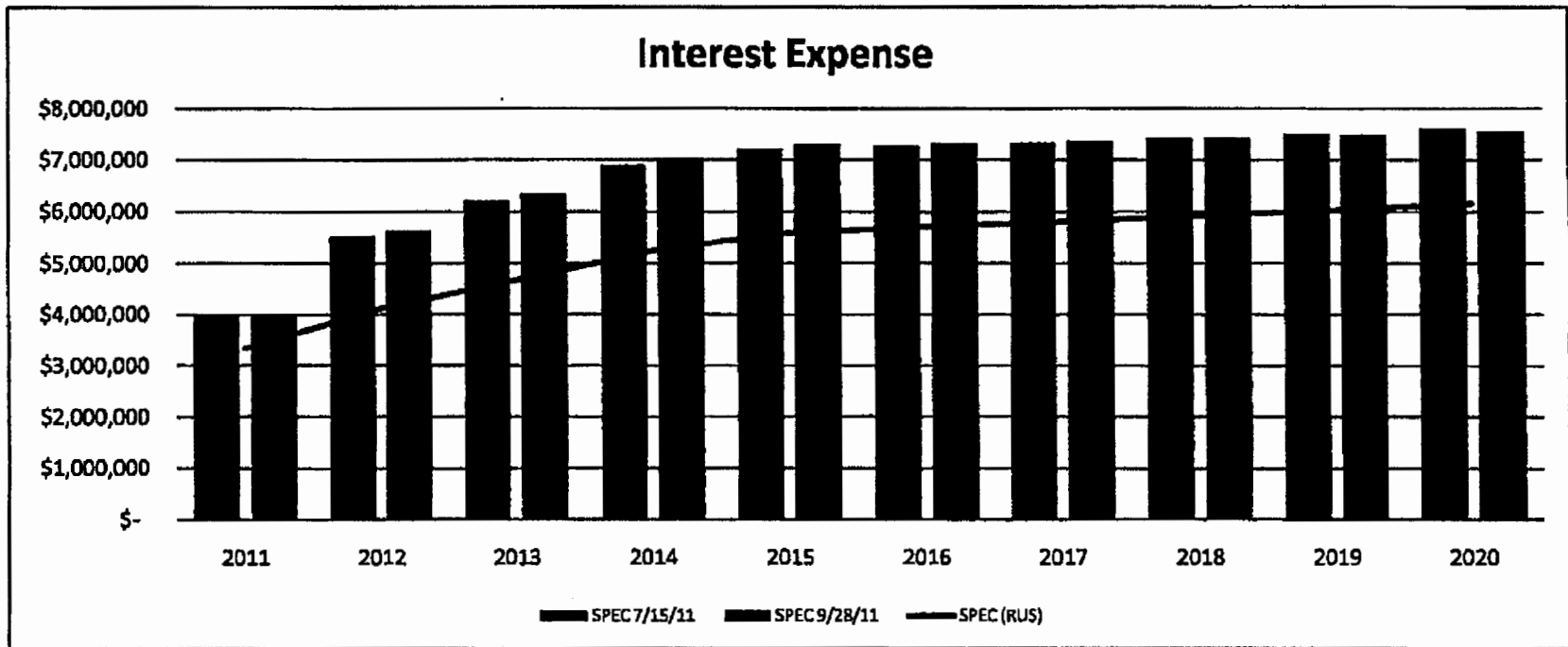


SPEC 7/15/11
SPEC 9/28/11
SPEC (RUS)

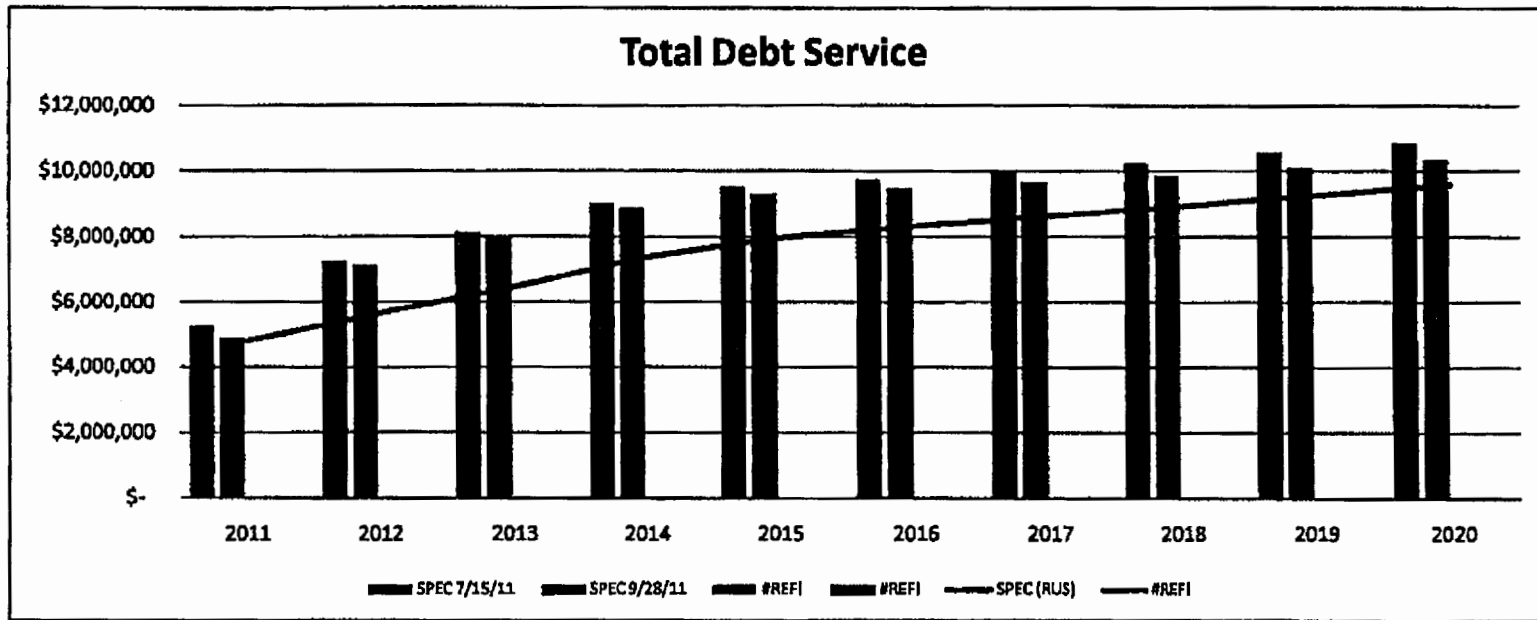
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SPEC 7/15/11	0.06	0.07	3.81	7.19	10.63	13.79	16.68	19.34	21.81	24.14
SPEC 9/28/11	0.04	0.85	4.28	7.49	10.78	13.83	16.63	19.23	21.65	23.94
SPEC (RUS)	0.80	1.43	4.13	6.61	9.18	11.68	13.96	16.09	18.07	19.97



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SPEC 7/15/11	\$ 86,172,288	\$ 94,067,148	\$ 105,354,043	\$ 113,300,629	\$ 113,651,767	\$ 114,226,355	\$ 114,987,306	\$ 115,939,541	\$ 117,087,755	\$ 118,053,681
SPEC 9/28/11	\$ 94,502,238	\$ 102,619,837	\$ 114,148,709	\$ 121,463,945	\$ 121,351,894	\$ 121,475,476	\$ 121,799,327	\$ 122,327,820	\$ 123,065,155	\$ 123,632,588
SPEC (RUS)	\$ 83,441,048	\$ 91,522,485	\$ 102,933,001	\$ 111,972,360	\$ 114,443,422	\$ 115,780,315	\$ 117,307,005	\$ 119,011,139	\$ 120,900,222	\$ 122,596,704



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SPEC 7/15/11	\$ 4,000,750	\$ 5,523,893	\$ 6,212,210	\$ 6,903,215	\$ 7,212,213	\$ 7,264,735	\$ 7,332,848	\$ 7,415,504	\$ 7,513,124	\$ 7,612,691
SPEC 9/28/11	\$ 3,981,691	\$ 5,640,809	\$ 6,348,363	\$ 7,028,730	\$ 7,302,536	\$ 7,326,245	\$ 7,366,531	\$ 7,422,384	\$ 7,494,185	\$ 7,568,882
SPEC (RUS)	\$ 3,321,938	\$ 4,116,550	\$ 4,669,968	\$ 5,247,459	\$ 5,581,996	\$ 5,705,082	\$ 5,802,550	\$ 5,911,201	\$ 6,030,728	\$ 6,150,911



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SPEC 7/15/11	\$ 5,230,155	\$ 7,239,793	\$ 8,129,574	\$ 9,021,513	\$ 9,508,805	\$ 9,726,691	\$ 9,973,473	\$ 10,248,971	\$ 10,554,682	\$ 10,877,450
SPEC 9/28/11	\$ 4,881,146	\$ 7,133,970	\$ 8,023,751	\$ 8,881,304	\$ 9,305,188	\$ 9,464,351	\$ 9,651,026	\$ 9,864,890	\$ 10,107,196	\$ 10,364,532
SPEC (RUS)	\$ 4,782,583	\$ 5,645,873	\$ 6,463,711	\$ 7,387,915	\$ 7,950,585	\$ 8,324,044	\$ 8,640,191	\$ 8,937,795	\$ 9,253,158	\$ 9,583,658

SPEC 9/28/11

SOUTHERN PIONEER ELECTRIC COMPANY
K580

2011 RUS BUYOUT CASE - CoBank 4/22/11 Cashflow

Century 508
September 28, 2011

FINANCIAL FORECAST RUS FORM 325A- RATIOS

	LAST YEAR				FUTURE YEARS						
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1. EQUITY RATIO (WITH ADD. REV.) (%)	0.37	0.04	0.88	4.28	7.49	10.78	13.83	16.83	19.23	21.85	23.94
2a. DEBT SERVICE COVERAGE (WITH ADD. REV.)	2.40	1.23	1.27	1.71	1.70	1.98	1.67	1.88	1.84	1.92	1.80
2b. OPERATING DSC (including op. margins + G&T & lender CCs paid)		1.18	1.10	1.52	1.52	1.80	1.49	1.48	1.47	1.48	1.45
3a. TIMES INTEREST EARNED RATIO (WITH ADD. REV.)	1.70	0.93	1.17	1.74	1.74	1.73	1.73	1.72	1.72	1.71	1.71
3b. OPERATING TIER (including op. margins + G&T & lender CCs paid)		0.84	0.98	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
4. AVERAGE REVENUE PER KWH SOLD (CENTS)	8.11	8.57	9.84	10.87	11.13	11.80	11.92	12.31	12.79	13.19	13.59
5. INCREASE IN AVERAGE REVENUE PER KWH SOLD (%)		5.87	11.26	11.88	4.37	3.27	3.68	3.28	3.90	3.19	2.89
6. TOTAL UTILITY PLANT PER KWH SOLD (CENTS)	13.83	14.85	15.47	16.77	17.84	18.29	18.75	19.23	19.73	20.25	20.74
7. NET GENERAL FUNDS TO TOTAL UTILITY PLANT (%)	0.20	-0.78	-0.21	2.16	2.89	2.85	2.75	2.85	2.85	2.45	2.38
8. ACCUM. PROV. FOR DEP. & AMORT. TO T.U.P. (%)	28.37	21.54	19.77	16.99	15.44	15.83	15.83	16.09	16.12	16.22	16.40
9. OPERATIONS & MAINTENANCE EXP. PER CONSUMER (\$)	251.75	269.96	289.06	307.41	328.03	350.03	373.51	398.53	425.27	453.77	484.18
10. ADMIN. & GEN. EXPENSE PER CONSUMER (\$)	118.24	87.87	118.65	121.71	128.19	135.10	142.49	150.36	158.77	167.78	177.33
11. PLANT REVENUE RATIO	7.41	7.78	6.74	8.49	8.46	8.40	8.44	8.45	8.46	8.46	8.45
12. RATE OF RETURN ON RATE BASE (WITH ADD. REV.) (%)		3.88	8.33	8.35	8.44	8.43	8.12	7.88	7.88	7.46	7.28
13. RATE BASE = 104% OF NET UTILITY PLANT		85,899,513	83,754,899	108,442,040	119,808,368	120,882,280	128,336,893	129,840,731	134,788,757	139,887,334	144,849,888
14. INCREASE OVER PRESENT RETAIL RATES REQUIRED (%)		0.00	4.55	12.16	14.05	14.78	14.84	15.12	15.23	15.72	16.14
15. MODIFIED DSC (FOR RUS USE)		1.15	1.07	1.44	1.44	1.42	1.41	1.40	1.39	1.38	1.37
16. MODIFIED TIER (NET OF G&T & OTHER CAP. CREDITS)		0.84	0.92	1.40	1.40	1.40	1.39	1.39	1.39	1.39	1.39

FINANCIAL FORECAST RUS FORM 325B - PRO FORMA BALANCE SHEET

	LAST YEAR				FUTURE YEARS						
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1. ASSETS AND OTHER DEBITS											
a. TOTAL UTILITY PLANT	95,185,742	103,031,742	112,359,274	123,362,286	132,828,128	137,893,128	143,188,375	148,719,288	154,593,845	160,882,831	166,801,416
b. ACCUM. PROVISION FOR DEPREC. & AMORT.	26,103,028	22,628,364	22,020,230	20,854,141	20,514,372	21,583,241	22,870,421	23,778,277	24,901,195	26,045,578	27,322,870
c. NET UTILITY PLANT	70,082,716	82,403,378	90,339,044	102,508,145	112,313,756	116,309,884	120,317,954	124,941,011	129,692,650	134,837,253	139,478,546
d. NET GENERAL FUNDS	188,012	(802,904)	(238,298)	2,887,879	3,871,640	3,934,728	3,838,382	3,835,423	3,835,487	3,835,484	3,835,873
e. GENERAL FUNDS EXCLUDABLE ITEMS	0	0	0	0	0	0	0	0	0	0	0
f. OTHER ASSETS AND DEBITS	14,872,882	25,760,521	28,489,234	27,601,234	28,855,399	30,124,021	31,385,798	32,377,095	33,770,137	34,888,712	36,184,507
g. TOTAL ASSETS AND OTHER DEBITS	85,241,410	107,351,294	118,611,074	132,637,027	145,140,794	150,368,833	155,837,115	161,458,498	167,308,258	173,408,258	179,378,826
2. LIABILITIES AND OTHER CREDITS											
a. TOTAL MARGINS AND EQUITIES	316,384	41,724	984,805	8,680,988	10,889,517	16,209,407	21,554,307	28,848,839	32,173,103	37,535,770	42,939,008
b. LONG TERM DEBT - RUS											
(1). LONG TERM DEBT - 2% & 5%	0	0	0	0	0	0	0	0	0	0	0
(2). LONG TERM DEBT - 9% MUNI & TREASURY	54,637,637	0	0	0	0	0	0	0	0	0	0
(3). LONG TERM DEBT - GUARANTEE	0	84,420,138	83,498,759	82,527,415	81,503,397	80,423,849	80,289,789	80,086,863	80,821,084	80,487,824	81,081,853
(4). LESS CUSHION OF CREDIT	0	0	0	0	0	0	0	0	0	0	0
(5). TOTAL LONG TERM DEBT - RUS	54,637,637	84,420,138	83,498,759	82,527,415	81,503,397	80,423,849	80,289,789	80,086,863	80,821,084	80,487,824	81,081,853
c. LONG TERM DEBT - OTHER	6,304,386	30,882,130	38,121,078	61,821,284	59,980,848	60,028,046	62,189,717	63,713,374	66,505,738	67,671,931	69,380,736
d. CURRENT PORTION OF LONG TERM DEBT	0	1,483,181	1,875,388	1,652,574	2,002,852	2,138,105	2,284,485	2,442,806	2,613,011	2,795,850	2,795,850
e. LONG TERM DEBT - TOTAL	60,941,903	86,785,449	123,495,225	145,981,273	143,487,141	142,541,801	142,473,991	143,803,667	149,940,623	150,865,585	153,258,439
f. OTHER LIABILITIES AND CREDITS	23,863,123	14,380,494	14,462,721	14,689,908	14,809,884	14,945,438	15,081,828	15,240,830	15,420,344	15,602,982	16,802,682
g. TOTAL LIABILITIES AND OTHER CREDITS	85,241,410	107,351,294	118,611,074	132,637,027	145,140,794	150,368,833	155,837,115	161,458,498	167,308,258	173,408,258	179,378,826

SPEC 9/28/11

FINANCIAL FORECAST

RUS FORM 325C - STATEMENT OF OPERATIONS

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1. ACCRUAL BASIS										
a (1). ADDITIONAL REVENUE REQUIREMENTS FOR TIEREQUITY	0	3,074,710	8,666,739	10,391,852	11,349,811	11,851,298	12,696,408	13,320,731	14,429,066	15,397,345
(2). OPER. REV. & PATRON. CAP. - PRESENT RATES	62,811,400	67,553,057	71,187,932	73,940,771	76,807,581	80,547,372	83,993,029	88,170,585	91,803,888	95,370,264
b. COST OF POWER	49,282,509	53,943,541	57,984,256	59,957,815	62,632,174	66,176,273	69,422,944	73,398,159	78,825,671	80,182,835
c. OPER. REV. LESS COST OF POWER	13,528,891	16,682,228	22,450,418	24,374,808	25,524,318	26,322,396	27,265,494	28,293,156	29,407,253	30,864,775
d. OPERATIONS & MAINTENANCE EXPENSE	4,662,000	4,988,340	5,337,524	5,711,150	5,110,931	6,538,696	6,998,405	7,488,153	8,010,184	8,670,897
e. CONSUMER ACCOUNTS AND SALES EXPENSE	1,450,000	1,551,600	1,680,105	1,776,312	1,900,654	2,033,700	2,176,059	2,328,383	2,491,370	2,665,766
f. ADM. & GEN. & OTHER DEDUCTIONS EXPENSE	1,614,000	2,002,630	2,113,307	2,231,839	2,358,867	2,494,374	2,639,580	2,794,951	2,961,197	3,139,081
g. DEPRECIATION AND AMORTIZATION EXPENSE	2,304,338	2,465,100	2,705,183	2,914,175	3,028,298	3,141,429	3,262,818	3,389,728	3,622,436	3,655,142
h. TAX EXPENSE	269,381	487,641	1,746,311	1,884,376	1,834,888	1,931,327	1,846,725	1,965,107	1,996,609	2,008,711
l. INTEREST EXPENSE	3,981,891	5,840,809	6,348,363	7,028,730	7,302,536	7,326,245	7,368,531	7,422,384	7,494,195	7,568,862
j. TOTAL COST OF ELECTRIC SERVICE	63,463,899	71,061,461	77,306,049	81,604,397	85,265,140	89,642,015	93,811,062	98,784,868	103,291,651	107,791,314
k. PATRONAGE CAPITAL & OPERATING MARGINS	(652,499)	(463,694)	2,839,623	2,828,226	2,891,343	2,856,624	2,878,378	2,906,450	2,941,273	2,976,295
l. NON-OPERATING MARGINS	0	0	0	0	0	0	0	0	0	0
m. G&T AND OTHER CAPITAL CREDITS (CFC CTC's)	377,839	1,896,774	2,156,598	2,360,304	2,446,547	2,486,278	2,416,185	2,417,814	2,421,394	2,428,941
n. TOTAL ACCRUAL MARGINS	(274,650)	943,081	4,696,181	5,188,530	5,339,890	6,344,900	6,294,832	5,324,265	5,362,667	5,403,238
2. CASH BASIS										
a. CASH FROM OPERATIONS BEFORE DEBT SERVICE	5,533,530	7,652,215	11,593,169	12,771,131	13,219,178	13,324,299	13,507,725	13,718,582	13,967,893	14,200,320
b. TOTAL DEBT SERVICE	4,881,146	7,133,970	8,023,751	8,881,304	9,306,188	9,464,351	9,651,026	9,864,890	10,107,196	10,364,532
c. CASH MARGINS AFTER DEBT SERVICE	752,384	518,245	3,569,417	3,889,827	3,913,990	3,859,948	3,856,699	3,853,672	3,850,697	3,836,788

FINANCIAL FORECAST

RUS FORM 325D - GENERAL FUNDS SUMMARY

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1. SOURCES OF GENERAL FUNDS										
a. NET GENERAL FUNDS BEGINNING OF YEAR	186,012	(802,604)	(239,298)	2,687,679	3,971,640	3,934,728	3,935,362	3,935,423	3,935,467	3,935,484
b. CASH MARGINS AFTER DEBT SERVICE	752,384	518,245	3,569,417	3,889,827	3,913,990	3,859,948	3,856,699	3,853,672	3,850,697	3,836,788
c. OTHER PROCEEDS	(10,400,000)	648,061	1,064,689	1,106,139	1,179,525	1,228,498	1,224,890	1,224,741	1,226,819	1,228,148
d. SALE OF EXCLUDABLE ITEMS	0	0	0	0	0	0	0	0	0	0
e. REIMBURSEMENT FROM PRIORITY LOAN FUNDS	75,982,968	0	0	0	0	0	0	0	0	0
f. REIMBURSEMENT FROM SPECIAL LOANS (NON-PRIORITY)	0	0	0	0	0	0	0	0	0	0
g. USES OF CUSHION OF CREDIT ACCOUNT	0	0	0	0	0	0	0	0	0	0
2. TOTAL GENERAL FUNDS AVAILABLE	68,531,364	363,702	4,387,679	7,683,646	9,065,555	9,021,174	9,018,950	9,013,636	9,011,983	8,989,428
3. PROPOSED USE OF GENERAL FUNDS										
a. PURCHASE OF EXCLUDABLE ITEMS	0	0	0	0	0	0	0	0	0	0
b. CAPITAL CREDIT RETIREMENTS	0	0	0	0	0	0	0	0	0	0
c. GENERAL FUNDS INVESTED IN PLANT	1,841,000	600,000	1,700,000	3,712,004	5,130,828	5,085,812	5,081,528	5,078,369	5,076,490	5,083,764
d. OTHER USES OF GENERAL FUNDS	11,175,790	0	0	0	0	0	0	0	0	0
e. ADDITIONS TO CUSHION OF CREDIT ACCOUNT	0	0	0	0	0	0	0	0	0	0
f. ADDITIONAL PRINCIPAL PAYMENTS	64,317,178	0	0	0	0	0	0	0	0	0
4. TOTAL PROPOSED USES OF GENERAL FUNDS	67,333,968	600,000	1,700,000	3,712,004	5,130,828	5,085,812	5,081,528	5,078,369	5,076,490	5,083,764
5. NET GENERAL FUNDS - END OF YEAR	(802,604)	(236,298)	2,687,679	3,971,640	3,934,728	3,935,362	3,935,423	3,935,467	3,935,484	3,935,673

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	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1. DEBT & DEBT SERVICE - 2% & 5% LOANS										
a. DEBT FIRST OF YEAR	0	0	0	0	0	0	0	0	0	0
b. LOAN FUNDS ADVANCED	0	0	0	0	0	0	0	0	0	0
c. INTEREST	0	0	0	0	0	0	0	0	0	0
d. DEBT PAYMENTS	0	0	0	0	0	0	0	0	0	0
e. ADDITIONAL PRINCIPAL PAID	0	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	0	0	0	0	0	0	0	0	0	0
2. DEBT & DEBT SERVICE - OLD RUS										
a. DEBT FIRST OF YEAR	54,837,537	0	0	0	0	0	0	0	0	0
b. LOAN FUNDS ADVANCED	0	0	0	0	0	0	0	0	0	0
c. INTEREST	1,952,677	0	0	0	0	0	0	0	0	0
d. DEBT PAYMENTS	2,273,038	0	0	0	0	0	0	0	0	0
e. ADDITIONAL PRINCIPAL PAID	54,317,178	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	0	0	0	0	0	0	0	0	0	0
3. DEBT & DEBT SERVICE - NEW DEBT - RUS										
a. DEBT FIRST OF YEAR	0	0	0	0	0	0	0	0	0	0
b. LOAN FUNDS ADVANCED	0	0	0	0	0	0	0	0	0	0
c. INTEREST	0	0	0	0	0	0	0	0	0	0
d. DEBT PAYMENTS	0	0	0	0	0	0	0	0	0	0
e. ADDITIONAL PRINCIPAL PAID	0	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	0	0	0	0	0	0	0	0	0	0
4. DEBT & DEBT SERVICE - OLD DEBT - GUARANTEED										
a. DEBT FIRST OF YEAR	0	0	0	0	0	0	0	0	0	0
b. LOAN FUNDS ADVANCED	0	0	0	0	0	0	0	0	0	0
c. INTEREST	0	0	0	0	0	0	0	0	0	0
d. DEBT PAYMENTS	0	0	0	0	0	0	0	0	0	0
e. ADDITIONAL PRINCIPAL PAID	0	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	0	0	0	0	0	0	0	0	0	0
5. DEBT & DEBT SERVICE - NEW DEBT - GUARANTEED RUS BUYOUT										
a. DEBT FIRST OF YEAR	0	64,420,138	63,498,759	62,527,415	61,503,397	60,423,849	59,285,759	58,085,853	56,821,084	55,487,624
b. LOAN FUNDS ADVANCED	64,837,537	0	0	0	0	0	0	0	0	0
c. INTEREST	859,771	3,387,299	3,337,334	3,284,680	3,229,130	3,170,568	3,108,672	3,043,809	2,975,218	2,902,908
d. DEBT PAYMENTS	1,077,170	4,308,678	4,308,678	4,308,678	4,308,678	4,308,678	4,308,678	4,308,678	4,308,678	4,308,678
e. ADDITIONAL PRINCIPAL PAID	0	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	64,420,138	63,498,759	62,527,415	61,503,397	60,423,849	59,285,759	58,085,853	56,821,084	55,487,624	54,081,853
6. DEBT & DEBT SERVICE - OLD DEBT - OTHER										
a. DEBT FIRST OF YEAR	6,304,366	6,076,670	6,834,136	6,575,794	6,300,618	6,007,509	5,696,297	5,362,740	5,008,510	4,631,194
b. LOAN FUNDS ADVANCED	0	0	0	0	0	0	0	0	0	0
c. INTEREST	392,536	377,897	381,891	345,055	327,122	308,021	287,674	268,001	242,917	218,327
d. DEBT PAYMENTS	620,232	620,232	620,232	620,232	620,232	620,232	620,232	620,232	620,232	620,232
e. ADDITIONAL PRINCIPAL PAID	0	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	6,076,670	5,834,135	5,575,794	5,300,618	5,007,509	4,685,297	4,362,740	4,008,510	3,631,194	3,229,290
7. DEBT & DEBT SERVICE - NEW DEBT - OTHER										
a. DEBT FIRST OF YEAR	0	24,005,430	33,298,943	48,045,499	54,859,930	55,920,536	57,484,419	59,350,634	61,498,226	63,948,937
b. LOAN FUNDS ADVANCED	24,139,431	8,610,780	13,204,280	8,167,610	1,890,800	2,281,887	2,608,347	2,970,999	3,350,347	3,383,082
c. INTEREST	778,707	1,875,813	2,649,138	3,399,015	3,748,284	3,847,637	3,989,985	4,112,573	4,278,050	4,447,647
d. DEBT PAYMENTS	910,708	2,205,000	3,084,842	3,952,394	4,376,278	4,535,441	4,722,116	4,933,980	5,178,286	5,435,621
e. ADDITIONAL PRINCIPAL PAID	0	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	24,005,430	33,288,943	48,045,499	54,859,930	55,920,536	57,484,419	59,350,634	61,498,226	63,948,937	66,321,445
8. SUMMARY										
a. DEBT FIRST OF YEAR	80,841,903	94,502,238	102,619,837	114,148,709	121,463,945	121,351,894	121,475,478	121,799,327	122,327,820	123,065,155
b. LOAN FUNDS ADVANCED	88,778,968	9,610,780	13,204,280	8,167,610	1,890,800	2,281,887	2,608,347	2,970,999	3,350,347	3,383,082
c. INTEREST	3,981,691	6,640,809	8,348,363	7,028,730	7,302,639	7,328,245	7,388,531	7,422,384	7,484,185	7,568,882
d. DEBT PAYMENTS	4,881,146	7,133,970	8,023,751	8,881,304	9,305,188	9,464,351	9,851,028	9,864,890	10,107,196	10,364,632
e. ADDITIONAL PRINCIPAL PAID	54,317,178	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	84,502,238	102,619,837	114,148,709	121,463,945	121,351,894	121,475,478	121,799,327	122,327,820	123,066,166	123,632,688

New C Bank

SPEC 7/15/11

SOUTHERN PIONEER ELECTRIC COMPANY
KS80

2011 RUS BUYOUT CASE - CoBank 4/22/11 Cashflows

Charity Scott
July 15, 2011

FINANCIAL FORECAST RUS FORM 325A- RATIOS

LAST YEAR	FUTURE YEARS										
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1. EQUITY RATIO (WITH ADD. REV.) (%)	0.37	0.08	0.07	3.81	7.19	10.83	13.79	18.08	19.34	21.81	24.14
2a. DEBT SERVICE COVERAGE (WITH ADD. REV.)	2.40	1.18	1.11	1.88	1.85	1.83	1.81	1.89	1.87	1.85	1.83
2b. OPERATING DSC (including op. margins + G&T & lender CCo paid)		1.09	0.98	1.48	1.47	1.45	1.44	1.43	1.42	1.40	1.39
3a. TIMES INTEREST EARNED RATIO (WITH ADD. REV.)	1.70	0.94	1.00	1.74	1.74	1.73	1.73	1.72	1.71	1.71	1.71
3b. OPERATING TIER (including op. margins + G&T & lender CCo paid)		0.86	0.80	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
4. AVERAGE REVENUE PER KWH SOLD (CENTS)	8.11	8.67	9.35	10.60	11.07	11.44	11.87	12.27	12.78	13.18	13.58
5. INCREASE IN AVERAGE REVENUE PER KWH SOLD (%)		5.67	0.16	13.25	4.42	3.36	3.73	3.32	3.88	3.24	3.03
6. TOTAL UTILITY PLANT PER KWH SOLD (CENTS)	13.83	14.05	15.47	16.77	17.84	18.29	18.75	19.23	19.73	20.28	20.74
7. NET GENERAL FUNDS TO TOTAL UTILITY PLANT (%)	0.20	1.26	0.32	2.07	3.00	2.86	2.78	2.85	2.85	2.48	2.37
8. ACCUM. PROCN. FOR DEP. & AMORT. TO T.U.P. (%)	28.37	21.54	19.77	16.99	16.44	15.85	15.83	15.99	-18.12	16.22	16.40
9. OPERATIONS & MAINTENANCE EXP. PER CONSUMER (\$)	261.78	280.98	288.08	307.41	328.03	350.03	373.81	398.56	425.27	453.77	484.18
10. ADMIN. & GEN. EXPENSE PER CONSUMER (\$)	118.24	85.94	87.17	103.28	109.81	118.77	124.21	132.14	140.00	149.82	159.28
11. PLANT REVENUE RATIO	7.41	7.78	7.31	6.81	6.58	6.49	6.81	6.52	6.52	6.51	6.48
12. RATE OF RETURN ON RATE BASE (WITH ADD. REV.) (%)		3.93	4.47	8.21	8.33	8.39	8.09	7.89	7.89	7.51	7.36
13. RATE BASE = 104% OF NET UTILITY PLANT		83,889,813	93,784,999	106,442,040	118,808,308	120,982,280	128,336,883	129,840,731	134,788,787	139,887,334	144,848,898
14. INCREASE OVER PRESENT RETAIL RATES REQUIRED (%)		0.00	2.90	11.80	13.44	14.28	14.30	14.74	15.02	15.45	15.92
15. MODIFIED DSC (FOR RUS USE)		1.08	0.92	1.41	1.40	1.38	1.37	1.35	1.34	1.33	1.32
16. MODIFIED TIER (NET OF G&T & OTHER CAP. CREDITS)		0.84	0.76	1.41	1.41	1.40	1.40	1.40	1.40	1.40	1.40

FINANCIAL FORECAST RUS FORM 325B - PRO FORMA BALANCE SHEET

LAST YEAR	FUTURE YEARS										
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1. ASSETS AND OTHER DEBITS											
a. TOTAL UTILITY PLANT	90,180,742	109,091,742	112,359,374	123,302,250	132,828,126	137,893,126	143,186,975	148,719,288	154,503,846	160,562,831	166,801,416
b. ACCUM. PROVISION FOR DEPREC. & AMORT.	26,103,026	22,628,364	22,210,236	20,854,141	20,614,372	21,583,241	22,670,421	23,778,277	24,901,198	26,048,578	27,322,670
c. NET UTILITY PLANT	70,082,716	82,403,378	90,149,038	102,348,115	112,313,756	116,309,884	120,515,935	124,943,011	129,602,658	134,502,082	139,278,746
d. NET GENERAL FUNDS	169,012	1,313,368	357,808	2,551,731	3,884,288	3,949,400	3,948,284	3,948,603	3,948,640	3,947,826	3,947,602
e. GENERAL FUNDS EXCLUDABLE ITEMS	0	0	0	0	0	0	0	0	0	0	0
f. OTHER ASSETS AND DEBITS	14,972,682	18,320,621	16,448,471	17,936,118	18,578,843	21,739,785	22,896,285	24,483,084	26,074,141	27,668,387	29,287,008
g. TOTAL ASSETS AND OTHER DEBITS	85,241,410	99,037,265	108,953,316	122,836,962	135,874,882	141,498,069	147,388,533	153,373,278	159,623,742	166,132,744	172,493,654
2. LIABILITIES AND OTHER CREDITS											
a. TOTAL MARGINS AND EQUITIES	318,344	67,895	78,836	4,874,588	9,786,921	18,036,069	20,324,846	25,878,640	30,878,869	36,227,867	41,632,842
b. LONG TERM DEBT - RUS											
(1). LONG TERM DEBT - 2% & 5%	0	0	0	0	0	0	0	0	0	0	0
(2). LONG TERM DEBT - 5% MUNI & TREASURY	54,637,537	0	0	0	0	0	0	0	0	0	0
(3). LONG TERM DEBT - GUARANTEE	0	58,687,412	66,437,468	54,217,934	82,924,508	81,682,964	60,098,385	48,566,740	48,016,758	48,184,763	43,344,772
(4). LESS CUSHION OF CREDIT	0	0	0	0	0	0	0	0	0	0	0
(5). TOTAL LONG TERM DEBT - RUS	54,637,537	58,687,412	66,437,468	54,217,934	82,924,508	81,682,964	60,098,385	48,566,740	48,016,758	48,184,763	43,344,772
c. LONG TERM DEBT - OTHER	6,304,396	29,884,878	38,629,880	51,136,109	60,378,031	62,068,773	64,137,970	66,431,567	69,019,783	71,902,992	74,708,909
d. CURRENT PORTION OF LONG TERM DEBT	0	1,718,000	1,817,365	2,118,298	2,296,892	2,461,856	2,640,625	2,833,467	3,041,559	3,284,758	3,564,739
e. LONG TERM DEBT - TOTAL	60,941,933	84,468,368	82,149,783	103,235,746	111,004,037	111,189,811	111,885,730	112,163,839	112,897,982	113,822,998	114,788,922
f. OTHER LIABILITIES AND CREDITS	23,983,123	14,523,232	14,724,897	14,925,831	15,103,825	15,299,289	15,447,867	15,640,799	15,848,881	16,072,091	16,312,091
g. TOTAL LIABILITIES AND OTHER CREDITS	85,241,410	99,037,265	108,953,316	122,836,962	135,874,882	141,498,069	147,388,533	153,373,278	159,623,742	166,132,744	172,493,654

SPEC 7/15/11

FINANCIAL FORECAST

RUS FORM 325C - STATEMENT OF OPERATIONS

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1. ACCRUAL BASIS										
a (1) ADDITIONAL REVENUE REQUIREMENTS FOR TIER/EQUITY	0	1,758,648	8,188,101	9,940,746	10,952,318	11,591,004	12,578,040	13,238,846	14,184,294	15,187,967
(2) OPER. REV. & PATRON. CAP. - PRESENT RATES	82,811,400	87,653,067	71,187,832	73,940,771	76,807,881	80,547,372	83,993,029	88,170,585	91,803,868	95,370,264
b. COST OF POWER	49,282,509	53,845,541	67,394,256	69,967,816	82,632,174	68,179,273	69,422,944	73,388,159	76,826,871	80,182,835
c. OPER. REV. LESS COST OF POWER	13,628,891	16,368,164	21,981,778	23,923,701	25,127,726	25,965,103	26,948,126	28,012,272	29,162,481	30,374,797
d. OPERATIONS & MAINTENANCE EXPENSE	4,862,000	4,988,340	5,337,824	6,711,150	6,110,931	6,538,696	6,995,405	7,468,153	8,010,184	8,570,897
e. CONSUMER ACCOUNTS AND SALES EXPENSE	1,450,000	1,531,500	1,660,106	1,778,312	1,900,654	2,033,700	2,178,059	2,328,383	2,491,370	2,665,788
f. ADM. & GEN. & OTHER DEDUCTIONS EXPENSE	1,479,000	1,602,530	1,793,307	1,911,839	2,038,687	2,174,374	2,319,690	2,474,951	2,641,187	2,819,081
g. DEPRECIATION AND AMORTIZATION EXPENSE	2,304,338	2,465,100	2,705,183	2,914,175	3,025,298	3,141,429	3,262,818	3,389,728	3,522,436	3,658,142
h. TAX EXPENSE	269,391	467,841	1,748,311	1,884,378	1,934,888	1,931,327	1,946,726	1,985,107	1,988,808	2,008,711
i. INTEREST EXPENSE	4,000,750	6,523,893	6,212,210	6,903,215	7,212,213	7,284,735	7,332,848	7,418,604	7,513,124	7,612,891
j. TOTAL COST OF ELECTRIC SERVICE	63,447,958	70,844,545	76,848,896	81,058,882	84,854,826	89,260,636	93,467,378	98,457,986	102,990,591	107,515,123
k. PATRONAGE CAPITAL & OPERATING MARGINS (638,558)	(1,332,840)	2,527,138	2,822,634	2,805,074	2,880,841	2,813,690	2,952,445	2,997,562	3,042,509	3,042,509
l. NON-OPERATING MARGINS	0	0	0	0	0	0	0	0	0	0
m. G&T AND OTHER CAPITAL CREDITS (CFC CTC's)	377,839	1,354,011	2,068,612	2,269,700	2,363,974	2,408,036	2,340,103	2,345,784	2,353,228	2,362,478
n. TOTAL ACCRUAL MARGINS (258,719)	21,171	4,585,750	5,092,334	5,092,334	5,269,048	5,288,877	5,253,794	5,298,229	5,350,758	5,404,885
2. CASH BASIS										
a. CASH FROM OPERATIONS BEFORE DEBT SERVICE	6,663,630	6,656,163	11,444,531	12,840,024	13,142,586	13,287,006	13,609,357	13,757,578	14,033,121	14,310,342
b. TOTAL DEBT SERVICE	6,230,156	7,239,783	8,129,574	8,021,513	9,808,805	9,728,891	9,973,473	10,248,971	10,554,882	10,877,450
c. CASH MARGINS AFTER DEBT SERVICE	433,475	(583,620)	3,314,957	3,618,511	3,633,780	3,580,314	3,635,884	3,608,706	3,478,439	3,432,892

FINANCIAL FORECAST

RUS FORM 326D - GENERAL FUNDS SUMMARY

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1. SOURCES OF GENERAL FUNDS										
a. NET GENERAL FUNDS BEGINNING OF YEAR	188,012	1,313,386	357,608	2,551,731	3,984,286	3,948,400	3,948,284	3,946,603	3,946,950	3,947,325
b. CASH MARGINS AFTER DEBT SERVICE	438,375	(583,640)	3,314,958	3,618,511	3,633,780	3,560,314	3,635,884	3,608,706	3,478,439	3,432,892
c. OTHER PROCEEDS	30,000	228,061	578,967	628,974	701,032	751,626	762,734	765,307	769,000	763,837
d. SALE OF EXCLUDABLE ITEMS	0	0	0	0	0	0	0	0	0	0
e. REIMBURSEMENT FROM PRIORITY LOAN FUNDS	67,992,968	0	0	0	0	0	0	0	0	0
f. REIMBURSEMENT FROM SPECIAL LOANS (NON-PRIORITY)	0	0	0	0	0	0	0	0	0	0
g. USES OF CUSHION OF CREDIT ACCOUNT	0	0	0	0	0	0	0	0	0	0
2. TOTAL GENERAL FUNDS AVAILABLE	68,647,355	957,808	4,251,731	6,799,215	8,319,097	8,267,240	8,234,901	8,210,617	8,184,389	8,144,054
3. PROPOSED USE OF GENERAL FUNDS										
a. PURCHASE OF EXCLUDABLE ITEMS	0	0	0	0	0	0	0	0	0	0
b. CAPITAL CREDIT RETIREMENTS	0	0	0	0	0	0	0	0	0	0
c. GENERAL FUNDS INVESTED IN PLANT	1,841,000	600,000	1,700,000	2,814,930	4,373,698	4,310,958	4,288,298	4,283,866	4,237,064	4,196,152
d. OTHER USES OF GENERAL FUNDS	11,175,790	0	0	0	0	0	0	0	0	0
e. ADDITIONS TO CUSHION OF CREDIT ACCOUNT	0	0	0	0	0	0	0	0	0	0
f. ADDITIONAL PRINCIPAL PAYMENTS	54,317,178	0	0	0	0	0	0	0	0	0
4. TOTAL PROPOSED USES OF GENERAL FUNDS	67,333,968	600,000	1,700,000	2,814,930	4,373,698	4,310,958	4,288,298	4,283,866	4,237,064	4,196,152
5. NET GENERAL FUNDS - END OF YEAR	1,313,386	357,808	2,551,731	3,984,286	3,948,400	3,948,284	3,946,603	3,946,950	3,947,325	3,947,902

SPEL 7/15/11

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1. DEBT & DEBT SERVICE - 2% & 5% LOANS										
a. DEBT FIRST OF YEAR	0	0	0	0	0	0	0	0	0	0
b. LOAN FUNDS ADVANCED	0	0	0	0	0	0	0	0	0	0
c. INTEREST	0	0	0	0	0	0	0	0	0	0
d. DEBT PAYMENTS	0	0	0	0	0	0	0	0	0	0
e. ADDITIONAL PRINCIPAL PAID	0	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	0	0	0	0	0	0	0	0	0	0
2. DEBT & DEBT SERVICE - OLD RUS										
a. DEBT FIRST OF YEAR	64,637,537	0	0	0	0	0	0	0	0	0
b. LOAN FUNDS ADVANCED	0	0	0	0	0	0	0	0	0	0
c. INTEREST	1,171,808	0	0	0	0	0	0	0	0	0
d. DEBT PAYMENTS	1,491,985	0	0	0	0	0	0	0	0	0
e. ADDITIONAL PRINCIPAL PAID	54,317,178	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	0	0	0	0	0	0	0	0	0	0
3. DEBT & DEBT SERVICE - NEW DEBT - RUS										
a. DEBT FIRST OF YEAR	0	0	0	0	0	0	0	0	0	0
b. LOAN FUNDS ADVANCED	0	0	0	0	0	0	0	0	0	0
c. INTEREST	0	0	0	0	0	0	0	0	0	0
d. DEBT PAYMENTS	0	0	0	0	0	0	0	0	0	0
e. ADDITIONAL PRINCIPAL PAID	0	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	0	0	0	0	0	0	0	0	0	0
4. DEBT & DEBT SERVICE - OLD DEBT - GUARANTEED										
a. DEBT FIRST OF YEAR	0	0	0	0	0	0	0	0	0	0
b. LOAN FUNDS ADVANCED	0	0	0	0	0	0	0	0	0	0
c. INTEREST	0	0	0	0	0	0	0	0	0	0
d. DEBT PAYMENTS	0	0	0	0	0	0	0	0	0	0
e. ADDITIONAL PRINCIPAL PAID	0	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	0	0	0	0	0	0	0	0	0	0
5. DEBT & DEBT SERVICE - NEW DEBT - <i>Rus Buyout</i> GUARANTEED										
a. DEBT FIRST OF YEAR	0	50,567,412	55,437,468	54,217,834	52,924,598	51,552,984	50,098,385	48,555,749	46,919,758	45,184,763
b. LOAN FUNDS ADVANCED	57,137,537	0	0	0	0	0	0	0	0	0
c. INTEREST	1,676,989	3,302,284	3,232,694	3,158,892	3,080,624	2,997,619	2,909,592	2,816,237	2,717,233	2,612,237
d. DEBT PAYMENTS	2,228,114	4,452,228	4,452,228	4,452,228	4,452,228	4,452,228	4,452,228	4,452,228	4,452,228	4,482,228
e. ADDITIONAL PRINCIPAL PAID	0	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	58,587,412	55,437,468	54,217,834	52,924,598	51,552,984	50,098,385	48,555,749	46,919,758	45,184,763	43,344,772
6. DEBT & DEBT SERVICE - OLD DEBT - OTHER										
a. DEBT FIRST OF YEAR	8,304,368	8,078,670	5,834,135	5,575,794	5,300,618	5,007,509	4,685,297	4,362,740	4,008,510	3,631,194
b. LOAN FUNDS ADVANCED	0	0	0	0	0	0	0	0	0	0
c. INTEREST	392,538	377,697	381,891	345,055	327,122	308,021	287,674	268,001	242,917	218,327
d. DEBT PAYMENTS	620,232	620,232	620,232	620,232	620,232	620,232	620,232	620,232	620,232	620,232
e. ADDITIONAL PRINCIPAL PAID	0	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	6,076,670	5,834,135	5,575,794	5,300,618	5,007,509	4,685,297	4,362,740	4,008,510	3,631,194	3,229,290
7. DEBT & DEBT SERVICE - NEW DEBT - <i>New Co Bank</i> OTHER										
a. DEBT FIRST OF YEAR	0	23,508,208	32,795,545	45,560,314	55,075,413	57,091,285	59,432,672	62,068,817	65,011,273	68,271,798
b. LOAN FUNDS ADVANCED	23,639,431	9,610,780	13,204,280	10,064,885	2,847,730	3,038,543	3,401,578	3,785,702	4,189,773	4,230,684
c. INTEREST	780,819	1,843,912	2,617,625	3,399,268	3,804,487	3,959,095	4,135,582	4,333,266	4,552,874	4,782,127
d. DEBT PAYMENTS	891,845	2,167,333	3,057,115	3,948,053	4,436,345	4,654,231	4,901,013	5,176,512	5,482,223	5,804,860
e. ADDITIONAL PRINCIPAL PAID	0	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	23,508,208	32,795,545	45,580,314	55,075,413	57,091,285	59,432,672	62,068,817	65,011,273	68,271,798	71,479,819
8. SUMMARY										
a. DEBT FIRST OF YEAR	80,941,908	88,172,288	94,067,148	105,354,043	113,300,629	113,851,787	114,226,355	114,987,306	115,939,541	117,087,755
b. LOAN FUNDS ADVANCED	80,778,968	9,610,780	13,204,280	10,064,885	2,847,730	3,038,543	3,401,578	3,785,702	4,189,773	4,230,684
c. INTEREST	4,000,750	5,623,883	6,212,210	6,803,215	7,212,213	7,284,735	7,332,848	7,415,504	7,513,124	7,612,891
d. DEBT PAYMENTS	5,230,155	7,239,793	8,129,574	9,021,513	9,508,805	9,728,691	9,973,473	10,248,971	10,554,682	10,877,450
e. ADDITIONAL PRINCIPAL PAID	54,317,178	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	88,172,288	94,067,148	105,354,043	113,300,629	113,851,787	114,226,355	114,987,306	115,939,541	117,087,755	118,053,681

SOUTHERN PIONEER ELECTRIC COMPANY
K660

2011 Adjusted Base Case - No RUS Buyout

Charley Scott
July 18, 2011

SPEC (RUS)

FINANCIAL FORECAST RUS FORM 325A- RATIOS

	LAST YEAR	FUTURE YEARS									
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1. EQUITY RATIO (WITH ADD. REV.) (%)	0.97	0.80	1.43	4.13	8.81	9.18	11.88	13.98	18.09	18.07	19.97
2a. DEBT SERVICE COVERAGE (WITH ADD. REV.)	2.40	1.27	1.30	1.88	1.83	1.88	1.58	1.82	1.81	1.48	1.47
2b. OPERATING DSC (including op. margins + G&T & tender CCs paid)		1.20	1.14	1.50	1.40	1.43	1.41	1.38	1.37	1.36	1.34
3a. TIMES INTEREST EARNED RATIO (WITH ADD. REV.)	1.70	1.14	1.18	1.74	1.73	1.72	1.72	1.71	1.70	1.70	1.70
3b. OPERATING TIER (including op. margins + G&T & tender CCs paid)		1.03	0.98	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50
4. AVERAGE REVENUE PER KWH SOLD (CENTS)	8.11	8.87	9.30	10.34	10.80	11.18	11.64	12.04	12.44	12.98	13.37
5. INCREASE IN AVERAGE REVENUE PER KWH SOLD (%)		8.87	8.03	11.22	4.41	3.82	4.03	3.48	4.10	3.38	3.14
6. TOTAL UTILITY PLANT PER KWH SOLD (CENTS)	13.83	14.85	18.47	18.77	17.84	18.28	18.75	19.23	19.73	20.28	20.74
7. NET GENERAL FUNDS TO TOTAL UTILITY PLANT (%)	0.20	-0.67	-0.47	0.82	2.04	2.88	2.77	2.88	2.88	2.47	2.38
8. ACCUM. PROV. FOR DEP. & AMORT. TO T.U.P. (%)	28.57	21.54	19.77	18.98	15.44	15.85	15.83	16.88	18.12	18.22	18.40
9. OPERATIONS & MAINTENANCE EXP. PER CONSUMER (\$)	251.75	268.08	288.08	307.41	328.03	350.03	373.81	398.55	425.27	453.77	484.18
10. ADMIN. & GEN. EXPENSE PER CONSUMER (\$)	118.24	83.82	81.39	97.52	104.07	111.03	118.48	128.44	134.91	143.88	153.80
11. PLANT REVENUE RATIO	7.41	7.76	7.80	8.14	8.08	5.94	5.61	5.88	5.88	5.83	5.78
12. RATE OF RETURN ON RATE BASE (WITH ADD. REV.) (%)		3.87	4.18	8.52	8.88	8.87	8.78	8.88	8.83	8.42	8.33
13. RATE BASE = 104% OF NET UTILITY PLANT		85,898,813	89,754,989	108,442,040	118,808,305	120,882,280	125,338,563	129,940,731	134,788,757	139,887,334	144,848,898
14. INCREASE OVER PRESENT RENTAL RATES REQUIRED (%)		0.00	2.03	8.83	10.71	11.77	12.22	12.71	13.13	13.88	14.28
15. MODIFIED DSC (FOR RUS USE)		1.19	1.13	1.48	1.45	1.43	1.40	1.38	1.38	1.35	1.34
16. MODIFIED TIER (NET OF G&T & OTHER CAP. CREDITS)		1.02	0.85	1.48	1.48	1.49	1.48	1.48	1.48	1.48	1.48

FINANCIAL FORECAST RUS FORM 325B - PRO FORMA BALANCE SHEET

	LAST YEAR	FUTURE YEARS									
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1. ASSETS AND OTHER DEBITS											
a. TOTAL UTILITY PLANT	95,185,742	106,031,742	112,398,274	123,302,258	132,828,128	137,883,128	148,188,375	148,718,288	154,603,845	160,552,831	168,801,418
b. ACCUM. PROVISION FOR DEPRECIATION & AMORT.	25,103,028	22,828,384	22,210,238	20,954,141	20,514,372	21,563,241	22,870,421	23,778,277	24,801,185	26,048,878	27,322,870
c. NET UTILITY PLANT	70,082,718	82,403,378	90,148,038	102,348,115	112,313,755	116,309,884	125,317,954	124,940,011	129,802,660	134,504,953	139,278,548
d. NET GENERAL FUNDS	188,012	(704,041)	(632,828)	1,013,487	2,710,848	3,878,878	3,980,240	3,881,149	3,881,244	3,881,289	3,881,833
e. GENERAL FUNDS EXCLUDABLE ITEMS	0	0	0	0	0	0	0	0	0	0	0
f. OTHER ASSETS AND DEBITS	14,872,882	15,320,521	18,232,144	17,368,101	18,883,280	18,838,978	21,118,737	22,324,387	23,531,741	24,737,714	25,942,217
g. TOTAL ASSETS AND OTHER DEBITS	85,241,410	97,018,858	105,848,255	120,728,713	133,817,861	140,120,738	149,501,831	151,228,848	157,066,835	163,268,655	168,182,488
2. LIABILITIES AND OTHER CREDITS											
a. TOTAL MARGINS AND EQUITIES	318,384	771,477	1,818,438	4,980,378	8,838,288	12,888,884	17,004,284	21,114,208	26,277,184	32,488,501	39,778,458
b. LONG TERM DEBT - RUS											
(1). LONG TERM DEBT - 2% & 8%	0	0	0	0	0	0	0	0	0	0	0
(2). LONG TERM DEBT - 8%, MUNI & TREASURY	54,837,837	53,404,588	52,117,800	50,774,818	48,373,182	47,010,331	48,383,589	44,780,188	43,127,127	41,361,447	38,578,944
(3). LONG TERM DEBT - GUARANTEE	0	23,968,790	33,870,860	46,582,380	57,288,890	81,525,681	84,701,428	88,184,108	71,878,608	75,877,580	78,787,470
(4). LESS CUSHION OF CREDIT	0	0	0	0	0	0	0	0	0	0	0
(5). TOTAL LONG TERM DEBT - RUS	54,837,837	77,373,378	86,088,660	97,357,207	106,671,742	108,438,913	111,088,017	112,944,286	115,002,829	117,268,027	118,367,414
c. LONG TERM DEBT - OTHER	8,304,388	8,078,870	8,834,135	8,578,794	8,300,818	8,007,608	4,806,287	4,382,740	4,008,510	3,831,194	3,228,280
d. CURRENT PORTION OF LONG TERM DEBT	0	1,528,324	1,793,744	2,140,456	2,368,568	2,618,982	2,837,840	3,026,984	3,222,430	3,432,747	3,432,747
e. LONG TERM DEBT - TOTAL	63,142,225	87,010,572	96,716,539	108,076,467	117,341,128	119,065,503	126,732,144	126,354,010	122,233,769	124,531,968	125,028,441
f. OTHER LIABILITIES AND CREDITS	23,863,123	14,338,656	14,801,078	14,847,788	15,178,821	18,426,294	18,644,873	18,833,827	18,028,783	16,240,078	16,240,078
g. TOTAL LIABILITIES AND OTHER CREDITS	86,241,410	97,018,858	105,848,255	120,728,713	133,817,861	140,120,738	149,501,831	151,228,848	157,066,835	163,268,655	168,182,488

SPEC (RUS)

FINANCIAL FORECAST RUS FORM 325C - STATEMENT OF OPERATIONS

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1. ACCRUAL BASIS										
a (1). ADDITIONAL REVENUE REQUIREMENTS FOR TIER/EQUITY	0	1,365,993	5,284,207	7,916,153	9,041,783	9,841,598	10,672,778	11,078,179	12,061,343	13,802,479
(2). OPER. REV. & PATRON. CAP. - PRESENT RATES	62,811,400	67,553,057	71,187,932	73,940,771	76,807,581	80,547,372	83,993,029	88,170,685	91,803,868	96,370,264
b. COST OF POWER	49,282,609	53,945,541	57,394,256	59,957,818	62,632,174	66,176,273	69,422,944	73,398,159	76,825,871	80,182,835
c. OPER. REV. LESS COST OF POWER	13,528,801	14,976,509	20,077,883	21,801,119	23,217,190	24,212,696	25,242,864	26,350,605	27,539,530	28,789,908
d. OPERATIONS & MAINTENANCE EXPENSE	4,852,000	4,888,340	5,337,524	5,711,150	5,110,931	6,538,696	6,996,405	7,486,153	8,010,184	8,570,897
e. CONSUMER ACCOUNTS AND SALES EXPENSE	1,460,000	1,651,500	1,680,105	1,776,317	1,800,654	2,033,700	2,178,059	2,328,383	2,491,370	2,665,765
f. ADM. & GEN. & OTHER DEDUCTIONS EXPENSE	1,444,000	1,582,530	1,693,307	1,811,839	1,938,867	2,074,374	2,219,580	2,374,801	2,541,197	2,719,081
g. DEPRECIATION AND AMORTIZATION EXPENSE	2,304,338	2,465,100	2,705,183	2,914,175	3,025,298	3,141,429	3,262,818	3,389,728	3,522,435	3,655,142
h. TAX EXPENSE	289,361	487,041	1,748,311	1,864,376	1,834,068	1,831,327	1,946,725	1,965,107	1,966,609	2,008,711
i. INTEREST EXPENSE	3,321,938	4,116,550	4,869,968	5,247,459	5,581,998	5,705,082	5,802,560	5,911,201	6,030,728	6,160,911
j. TOTAL COST OF ELECTRIC SERVICE	62,734,146	69,137,202	76,206,669	78,303,126	83,124,600	87,600,882	91,827,091	96,663,683	101,408,195	106,863,343
k. PATRONAGE CAPITAL & OPERATING MARGINS	77,254	(215,151)	2,265,488	2,555,808	2,724,755	2,788,087	2,838,726	2,895,081	2,967,008	3,019,400
l. NON-OPERATING MARGINS	0	0	0	0	0	0	0	0	0	0
m. G&T AND OTHER CAPITAL CREDITS (CFC CTC's)	377,839	962,112	1,205,455	1,293,101	1,308,840	1,346,213	1,271,199	1,267,873	1,264,331	1,200,958
n. TOTAL ACCRUAL MARGINS	455,093	746,961	3,470,941	3,848,909	4,031,895	4,134,300	4,108,925	4,162,956	4,221,337	4,279,958
2. CASH BASIS										
a. CASH FROM OPERATIONS BEFORE DEBT SERVICE	5,703,530	6,366,498	9,840,636	10,717,442	11,332,050	11,634,690	11,904,096	12,196,011	12,510,170	12,825,453
b. TOTAL DEBT SERVICE	4,782,583	5,645,873	6,463,711	7,387,815	7,850,585	8,324,044	8,840,191	8,937,795	9,253,158	9,583,658
c. CASH MARGINS AFTER DEBT SERVICE	920,947	720,625	3,176,925	3,329,627	3,381,465	3,310,646	3,263,904	3,258,216	3,257,011	3,241,796

FINANCIAL FORECAST RUS FORM 325D - GENERAL FUNDS SUMMARY

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1. SOURCES OF GENERAL FUNDS										
a. NET GENERAL FUNDS BEGINNING OF YEAR	188,012	(704,041)	(532,926)	1,013,497	2,710,946	3,976,876	3,960,240	3,961,149	3,961,244	3,961,289
b. CASH MARGINS AFTER DEBT SERVICE	920,947	720,625	3,176,925	3,329,627	3,381,465	3,310,654	3,263,904	3,258,215	3,257,011	3,241,798
c. OTHER PROCEEDS	30,000	50,469	69,498	87,922	66,243	84,454	62,549	60,519	68,368	66,056
d. SALE OF EXCLUDABLE ITEMS	0	0	0	0	0	0	0	0	0	0
e. REIMBURSEMENT FROM PRIORITY LOAN FUNDS	11,175,790	0	0	0	0	0	0	0	0	0
f. REIMBURSEMENT FROM SPECIAL LOANS (NON-PRIORITY)	0	0	0	0	0	0	0	0	0	0
g. USES OF CUSHION OF CREDIT ACCOUNT	0	0	0	0	0	0	0	0	0	0
2. TOTAL GENERAL FUNDS AVAILABLE	12,312,750	67,074	2,719,497	4,410,946	6,158,653	7,351,884	7,286,693	7,279,884	7,278,513	7,259,140
3. PROPOSED USE OF GENERAL FUNDS										
a. PURCHASE OF EXCLUDABLE ITEMS	0	0	0	0	0	0	0	0	0	0
b. CAPITAL CREDIT RETIREMENTS	0	0	0	0	0	0	0	0	0	0
c. GENERAL FUNDS INVESTED IN PLANT	1,841,000	800,000	1,700,000	1,700,000	2,181,778	3,391,644	3,325,544	3,318,640	3,316,324	3,297,806
d. OTHER USES OF GENERAL FUNDS	11,175,790	0	0	0	0	0	0	0	0	0
e. ADDITIONS TO CUSHION OF CREDIT ACCOUNT	0	0	0	0	0	0	0	0	0	0
f. ADDITIONAL PRINCIPAL PAYMENTS	0	0	0	0	0	0	0	0	0	1
4. TOTAL PROPOSED USES OF GENERAL FUNDS	13,016,790	800,000	1,700,000	1,700,000	2,181,778	3,391,644	3,325,544	3,318,640	3,316,324	3,297,807
5. NET GENERAL FUNDS - END OF YEAR	(704,041)	(632,926)	1,013,497	2,710,946	3,976,876	3,960,240	3,961,149	3,961,244	3,961,289	3,961,533

	2011	2012	2013	2014	2015	2016	2017	2018	2018	2020
1. DEBT & DEBT SERVICE - 2% & 5% LOANS										
a. DEBT FIRST OF YEAR	0	0	0	0	0	0	0	0	0	0
b. LOAN FUNDS ADVANCED	0	0	0	0	0	0	0	0	0	0
c. INTEREST	0	0	0	0	0	0	0	0	0	0
d. DEBT PAYMENTS	0	0	0	0	0	0	0	0	0	0
e. ADDITIONAL PRINCIPAL PAID	0	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	0	0	0	0	0	0	0	0	0	0
2. DEBT & DEBT SERVICE - OLD RUS										
a. DEBT FIRST OF YEAR	64,637,537	63,404,688	62,117,800	60,774,816	49,373,182	47,910,831	46,383,688	44,780,159	43,127,127	41,891,447
b. LOAN FUNDS ADVANCED	0	0	0	0	0	0	0	0	0	0
c. INTEREST	2,330,408	2,278,567	2,220,373	2,161,722	2,100,606	2,036,613	1,969,827	1,900,324	1,827,677	1,751,853
d. DEBT PAYMENTS	3,563,356	3,563,356	3,563,356	3,563,356	3,563,356	3,563,356	3,563,356	3,563,356	3,563,356	3,563,356
e. ADDITIONAL PRINCIPAL PAID	0	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	63,404,688	62,117,800	60,774,816	49,373,182	47,910,331	46,383,589	44,780,159	43,127,127	41,391,447	39,579,944
3. DEBT & DEBT SERVICE - NEW DEBT - RUS										
a. DEBT FIRST OF YEAR	0	0	0	0	0	0	0	0	0	0
b. LOAN FUNDS ADVANCED	0	0	0	0	0	0	0	0	0	0
c. INTEREST	0	0	0	0	0	0	0	0	0	0
d. DEBT PAYMENTS	0	0	0	0	0	0	0	0	0	0
e. ADDITIONAL PRINCIPAL PAID	0	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	0	0	0	0	0	0	0	0	0	0
4. DEBT & DEBT SERVICE - OLD DEBT - GUARANTEED										
a. DEBT FIRST OF YEAR	0	0	0	0	0	0	0	0	0	0
b. LOAN FUNDS ADVANCED	0	0	0	0	0	0	0	0	0	0
c. INTEREST	0	0	0	0	0	0	0	0	0	0
d. DEBT PAYMENTS	0	0	0	0	0	0	0	0	0	0
e. ADDITIONAL PRINCIPAL PAID	0	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	0	0	0	0	0	0	0	0	0	0
5. DEBT & DEBT SERVICE - NEW DEBT - GUARANTEED										
a. DEBT FIRST OF YEAR	0	23,959,790	33,570,550	46,582,390	57,298,560	61,525,581	64,701,429	68,154,106	71,875,503	75,877,580
b. LOAN FUNDS ADVANCED	23,959,790	9,810,780	13,204,260	11,179,815	4,839,850	3,955,855	4,384,330	4,730,728	5,111,513	5,129,230
c. INTEREST	598,995	1,462,285	2,087,704	2,740,682	3,154,368	3,380,449	3,544,950	3,744,878	3,980,135	4,180,731
d. DEBT PAYMENTS	598,995	1,462,285	2,280,124	3,204,327	3,788,997	4,140,467	4,468,603	4,754,207	5,059,571	5,400,070
e. ADDITIONAL PRINCIPAL PAID	0	0	0	0	0	0	0	0	0	1
f. DEBT END OF YEAR	23,959,790	33,570,550	46,582,390	57,268,580	61,626,581	64,701,429	68,154,106	71,875,503	75,877,580	79,787,470
6. DEBT & DEBT SERVICE - OLD DEBT - OTHER										
a. DEBT FIRST OF YEAR	6,304,368	6,076,670	5,834,135	5,575,794	5,300,618	5,007,508	4,695,297	4,362,740	4,008,510	3,631,184
b. LOAN FUNDS ADVANCED	0	0	0	0	0	0	0	0	0	0
c. INTEREST	392,536	377,697	361,991	345,055	327,122	308,021	287,674	266,001	242,917	218,327
d. DEBT PAYMENTS	620,232	620,232	620,232	620,232	620,232	620,232	620,232	620,232	620,232	620,232
e. ADDITIONAL PRINCIPAL PAID	0	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	6,076,670	5,834,135	5,575,794	5,300,618	5,007,508	4,695,297	4,362,740	4,008,510	3,631,184	3,229,290
7. DEBT & DEBT SERVICE - NEW DEBT - OTHER										
a. DEBT FIRST OF YEAR	0	0	0	0	0	0	0	0	0	0
b. LOAN FUNDS ADVANCED	0	0	0	0	0	0	0	0	0	0
c. INTEREST	0	0	0	0	0	0	0	0	0	0
d. DEBT PAYMENTS	0	0	0	0	0	0	0	0	0	0
e. ADDITIONAL PRINCIPAL PAID	0	0	0	0	0	0	0	0	0	0
f. DEBT END OF YEAR	0	0	0	0	0	0	0	0	0	0
8. SUMMARY										
a. DEBT FIRST OF YEAR	60,841,803	63,441,048	61,522,485	102,933,001	111,972,360	114,443,422	115,780,315	117,307,005	119,011,139	120,900,222
b. LOAN FUNDS ADVANCED	23,959,790	9,810,780	13,204,260	11,179,815	4,839,850	3,955,855	4,384,330	4,730,728	5,111,513	5,129,230
c. INTEREST	3,321,938	4,118,550	4,669,968	5,247,458	5,581,896	5,705,062	5,802,580	5,911,201	6,030,728	6,150,911
d. DEBT PAYMENTS	4,782,583	5,945,873	6,463,711	7,367,915	7,960,685	8,324,044	8,640,191	8,837,795	9,253,158	9,583,658
e. ADDITIONAL PRINCIPAL PAID	0	0	0	0	0	0	0	0	0	1
f. DEBT END OF YEAR	83,441,048	91,522,485	102,933,001	111,972,360	114,443,422	115,780,315	117,307,005	119,011,139	120,900,222	122,586,704

New RUS

Old CoBank

SOUTHERN PIONEER ELECTRIC COMPANY

**INDEPENDENT AUDITOR'S REPORT
AND FINANCIAL STATEMENTS**

January 1, 2010 to December 31, 2010

INCOME TAX STATUS

The Company files Form 1120 for Federal and State income tax purposes.

(2) ASSETS PLEDGED:

Substantially all assets are pledged as security for long-term debt to RUS & CoBank.

(3) ELECTRIC PLANT AND DEPRECIATION PROCEDURES:

Listed below are the major classes of the electric plant as of December 31:

	<u>2010</u>	<u>2009</u>
Transmission plant	\$ 15,251,789.10	\$ 14,615,171.35
Distribution plant	37,156,168.71	34,529,424.49
General plant	<u>5,852,843.95</u>	<u>4,811,606.74</u>
Electric plant in service	58,260,801.76	53,956,202.58
Acquisition adjustment(net)	21,207,399.34	21,992,843.20
Construction work in progress	<u>13,366,556.05</u>	<u>12,421,385.02</u>
Total	<u>\$ 92,834,757.15</u>	<u>\$ 88,370,430.80</u>

The Company provides for depreciation on a straight line basis at annual rates which will amortize the depreciable property over its estimated useful life.

(4) INVESTMENTS:

At December 31, investments included:

	<u>2010</u>	<u>2009</u>
Net investment in MKEC	\$ 4,419,249.00	\$ 2,753,769.76
Fair value of plan assets	1,526,991.00	1,195,874.00
Investment in other organizations	507,416.89	266,150.81
Line extgension contracts receivable	<u>13,644.76</u>	<u>8,104.60</u>
Total	<u>\$ 6,467,301.65</u>	<u>\$ 4,223,899.17</u>

KANSAS ELECTRIC POWER COOPERATIVE, INC.
Information Request

Request No.1-6

Company Name MID-KANSAS ELECTRIC COMPANY, LLC
Docket Number 12-MKEE-380-RTS
Request Date February 3, 2012
Date Information Needed February 17, 2012
RE: MKEC's Application of December 20, 2011

Please provide the following:

With reference to Exhibit RJM-8, provide the following:

- a. An explanation as to whether the DSC Ratemaking Plan applies to proposed Schedule 11-LAC applicable to wholesale customers;

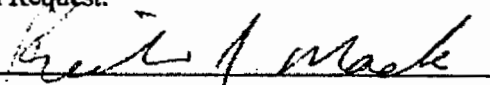
Response: Yes. The DSC Ratemaking Plan will track the non-power supply related revenue requirements (the PCA will track power supply costs) thus it can be applied to all the SPEC division rate schedules.

Submitted By KEPCo
Submitted To MKEC

If for some reason, the above information cannot be provided by the date requested, please provide a written explanation of those reasons.

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 KEPCo any matter subsequently discovered which affects the accuracy or completeness of the answer(s) to this Information Request.

Signed: 
Date: 2-17-12

CERTIFICATE OF SERVICE
(12-MKEE-380-RTS)

I, the undersigned, hereby certify that a true and correct copy of the above and foregoing was sent electronically on this 20th day of April, 2012, emailed to the following:

GLEND A CAFER, ATTORNEY
CAFER LAW OFFICE, L.L.C.
3321 SW 6TH STREET
TOPEKA, KS 66606

RAY BERGM EIER, LIT COUNSEL
KCC
1500 SW ARROWHEAD RD
TOPEKA, KS 66604-4027

TERRI PEMBERTON, ATTORNEY
CAFER LAW OFFICE, L.L.C.
3321 SW 6TH STREET
TOPEKA, KS 66606

HOLLY FISHER, ATTORNEY
KCC
1500 SW ARRHEAD RD
TOPEKA, KS 66604-4027

NIKKI CHRISTOPHER
C U R B
1500 ARROWHEAD
TOPEKA, KS 66604

LARRY HOLLOWAY, OPS MGR
KANSAS POWER POOL
200 W. DOUGLAS, STE 601
WICHITA, KS 67202

C. STEVEN RARRICK
C U R B
1500 ARROWHEAD
TOPEKA, KS 66604

COLIN M. WHITLEY, CEO/GEN MGR
KANSAS POWER POOL
200 W. DOUGLAS, STE 601
WICHITA, KS 67202

DELLA SMITH
C U R B
1500 ARROWHEAD
TOPEKA, KS 66604

MATTHEW SPURGIN, LIT COUNSEL
KANSAS CORP COMMISSION
1500 SW ARROWHEAD ROAD
TOPEKA, KS 66604-4027

SHONDA SMITH
C U R B
1500 ARROWHEAD
TOPEKA, KS 66604

DON GULLEY, SENIOR MANAGER
REGULATORY RELATIONS AND
BILLING
MID-KANSAS ELEC COMPANY, LLC
301 WEST 13TH STREET
PO BOX 980
HAYS, KS 67601

DAVID SPRINGE, CONS COUNSEL
C U R B
1500 SW ARROWHEAD ROAD
TOPEKA, KS 66604

RANDY MAGNISON, CHIEF
OPERATING OFFICER
SOUTHERN PIONEER ELEC CO
PO BOX 368
1850 W OKLAHOMA
ULYSSES, KS 67880-0368

CURTIS IRBY
GLAVES, IRBY & RHOADS
155 N. MARKET, #1050
WICHITA, KS 67202

MARK D. CALCARA, ATTORNEY
WATKINS CALCARA CHTD.
1321 MAIN STREET SUITE 300
PO DRAWER 1110
GREAT BEND, KS 67530

LINDSAY A. SHEPARD, ATTORNEY
WATKINS CALCARA CHTD.
1321 MAIN STREET SUITE 300
PO DRAWER 1110
GREAT BEND, KS 67530



J. Michael Peters