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BEFORE THE

KANSAS CORPORATION COMMISSION

DIRECT TESTIMONY OF THOMAS MEIS

ON BEHALF OF

MIDWEST ENERGY, INC.

DIRECT TESTIMONY OF THOMAS MEIS

Q: Please state your name, address and occupation.

A: Tom Meis. My business address is 1330 Canterbury Road, Hays, Kansas. I am the Vice President Finance, CFO for Midwest Energy, Inc. ("Midwest Energy" or "Company").

Q: Please describe your education and business experience.

A: I am a graduate of Fort Hays State University, holding a Bachelor of Science degree in Business Administration with an emphasis in Accounting. After graduation, I worked for two years as the Accounting Manager of Quinstar Corporation, an agricultural and turf equipment manufacturer in Quinter, Kansas. During that time, I received the designation of Certified Public Accountant. I then was promoted to Chief Financial Officer and worked in that position for an additional five years. In June of 2000, I was employed by Midwest Energy as the Accounting Administrator and served in that position until January of 2002, at which time I was promoted to Director of Finance. In May of 2002, I was promoted to Vice President of Finance and a few years ago named Vice President Finance, CFO.

Q: What are your current duties with the Company?

A: I am responsible for the financial, accounting and purchasing activities of the Company.

Q: What portion of the application in this proceeding are you sponsoring?

A: I am sponsoring all accounting and financial data contained in Sections 3 through Section 12 except Schedules 9-4 through 9-12 and 12-6 through 12-9 which are supported by Company witness Mr. Volker on behalf of Midwest Energy. In Section 7, additional testimony is provided by William Edwards of National Rural Utilities Cooperative Finance Corp. (NRUCFC) relating to capital structure and return on equity.

Q: Were the portions of the schedules that you are sponsoring prepared under your supervision and direction?

A: Yes, they were.

Q: What is presented in these schedules?

A: These statements present certain financial and statistical data for the test year ended August 31, 2010 and the preceding three calendar years, as required by the Commission's Rules and Regulations.

Q: Are you responsible for any questions regarding accounting matters of the Company that relate to transactions occurring during these time periods and during the Company's test year?

A: Yes, all questions relating to such matters can be directed to me.

SECTION 3 – RATE BASE, OPERATING INCOME AND RATE OF RETURN

Q: Please discuss your Kansas jurisdictional rate base, operating revenues and expenses and rate of return information contained in Schedule 3-1.

A: Schedule 3-1 contains the summary of the Company's rate base for the test period ending August 31, 2010, adjusted for items detailed in Sections 4 through 6. The full Kansas jurisdictional rate base included in Schedule 3-1 is $314,928,644. Lines 9 through 11 are a summary of the operating revenues, operating expenses and net operating margins for the Company on a pro forma basis for the test period. Line 12 shows our proposed rate of return of 6.8953 percent.

Q: What is the test year proposed by the Company in this rate increase application?

A: The Company, in this rate increase application, used the twelve-month period ending August 31, 2010.

Q: Schedule 3-2 includes investments in NRUCFC and CoBank, which are included as a component of rate base. Please discuss this entry.

A: As a condition of its mortgages, Midwest Energy is required to invest in NRUCFC and CoBank. On August 31, 2010, the Company had investments of $1,614,272 with NRUCFC on which the Company receives no return (see Schedule 7-8, Line 1). Since funds of the Company are used as a required investment, they are included as a rate base item. In addition, the Company has also included an amount of $5,549,548 for other required investments in NRUCFC on which it receives nominal interest income. This income has been included as revenue in this application to reduce the overall revenue requirement. Finally, the Company's lenders, as cooperative organizations themselves, allocate their margins to their borrower members and Midwest Energy has accumulated $5,180,484 of these "patronage dividends" (see Schedule 7-8, Lines 6 and 7). Since these investments represent deductions from interest expense, we have deducted their estimated impact from the cost of debt shown in Schedule 7-3. By deducting interest and dividend income from revenue requirements and including the required investments in rate base, we correctly reflect the total costs of obtaining the financing used to construct facilities and provide service to Midwest Energy's customers. Inclusion of these investments in rate base has been accepted by the Commission in past rate cases. Of the combined investment of $12,344,304, the amount allocated to electric operations (based on the gross plant-in-service allocation factor in Schedule 12-1) is $10,464,912.

Q: Please explain "Other Investments" as shown on Schedule 3-3.

A: These are Company investments in economic development and energy efficiency programs implemented to benefit our customers. We have $2,557,000 invested in the Rural Economic Development Loan and Grant Program (REDL&G) as of the end of the test period. USDA provides most of the funds for this program at near zero cost. Therefore, we have included the USDA loans and the associated low cost as part of our debt structure/cost as shown on Schedule 7-3. In addition, the Company invested over $2.4 million in the How$mart® energy efficiency program. A considerable portion of the that funding, over $700k, came from the Kansas Housing Resources Corporation ("KHRC") and more recently from Department of Energy Stimulus Fund monies funneled through the Efficiency Kansas ("EK") program of the State Energy Office of the KCC. Both the KHRC and EK funding is provided at zero percent interest. The zero cost funds from KHRC and EK are also included on Schedule 7-3 as part of the overall debt structure/cost of the Company.

It is worth noting that the Company is able to add some program costs and/or mark up the cost of debt used in funding the REDLEG and How$mart® programs. The revenue associated with repayment from customers participating in these programs is included as a pro forma adjustment as an offset to the requested revenue increase. The investment in both the REDL&G and How$mart® programs, as well as the associated revenues, are allocated to the electric and gas systems on the basis of customer meters.

Q: Please explain Schedule 3-4.

A: Schedule 3-4 shows customer advances for construction which are amounts provided by customers and are deducted from rate base. As of August 31, 2010, customer advances from electric customers equal $320,475.

SECTION 4 – PLANT IN SERVICE

Q: Will you please describe the financial data presented in each of the schedules of Section 4?

A: Yes. Schedule 4-1 presents a summary of electric plant in service by functional category as recorded and as adjusted at August 31, 2010. Pro forma adjustments to plant in service are detailed in Schedule 4-2. Also, account 114, Acquisition Adjustments, has been excluded from the schedule and is not included in rate base.

Q: Please discuss Schedule 4-2.

A: Schedule 4-2 provides the balance of electric plant in service by primary accounts for the calendar years ending December 31, 2007, 2008 and 2009 as well as the test year ending August 31, 2010. Pro forma adjustment (A) moves test year balances associated with engineering studies out of account 107 (construction work-in-progress, or CWIP) and adds the expected value into account 303 Intangibles. Pro forma adjustment (B) involves the last retainage payment of $940,000 due to the vendor that supplied the engines for GMEC. Since this amount was accrued into CWIP as of the end of the test year, the amount was deducted from account 107 and added to plant in service under account 341. Pro forma adjustment (C) addresses an investment made for a large new customer load. The projected total cost was added to plant in service under account 352. Since a portion of that project was included in CWIP as of the end of the test year, we deducted that amount from account 107.

Michael Volker has made related adjustments to revenues and purchased power costs associated with this new load. Pro forma adjustment (D) relates to the Core Enterprise System (CES) software implementation. The Company has already implemented new accounting and payroll software and is in the process of implementing a new customer information system (CIS) which is expected to be in service before the end of this rate proceeding. The total project is expected to cost $6 million. Since this software benefits both our electric and gas divisions, we have posted the amount to account 118 common plant. At the end of the test year, we had invested $2,065,000 in the project which was contained in account 107 CWIP. Therefore, we credited that account for the same. Pro forma adjustment (E) shows the retirement related to the CES project. Since this project replaces older software (estimated at $2 million), we credited account 118 and debited 108 accumulated depreciation for the same (see Schedule 5-1).

Q: Please describe Schedule 4-3 which presents detail on the allocated common plant and tell us what this schedule represents.

A: The allocated common plant in service shown on Schedule 4-3 was obtained from the sub-ledger accounts for common plant of the Company. Common plant is allocated to electric and gas plant in service by their respective totals of gross plant. Total common plant in service is shown on Line 9 while Lines 10 and 11 show the electric and gas percentages of gross plant. Line 22 shows the amount of common plant allocated to electric. The pro forma adjustments shown in column 6 relate to the CES project discussed above.

SECTION 5

ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION

Q: Please discuss Schedules 5-1 and 5-2 titled "Accumulated Depreciation."

A: Schedule 5-1 provides the balances per books for jurisdictional accumulated provision for depreciation and amortization of electric plant in service as of August 31, 2010. The retirement associated with the CES project (discussed above) is included in column 3, resulting in a total reserve balance of $159,934,797 shown on Line 11, Column 4. Line 12 contains the accumulated amortization of acquisition adjustments and is not included in rate base.

Q: Please continue.

A: Schedule 5-2 shows detailed information by functional account of the balances in the accumulated provision for depreciation and amortization of electric plant in service for calendar years 2007 through 2009, plus the end of the test year.

SECTION 6 – WORKING CAPITAL

Q: Please discuss Schedule 6-1, titled "Summary of Working Capital."

A: Schedule 6-1 presents the Company's proposed Kansas jurisdictional net working capital requirement of $8,571,425 that has been included as a rate base item on Schedule 3-1, Line 4. Lines 1 through 8 present detail on fuel stock, materials and supplies and prepaid insurance that comprise a part of the total working capital requirement amount. On Line 9, the Company has included a cash working capital requirement of $2,249,378 for non-purchased power O&M using one-eighth of the non-purchased power O&M expenses, a calculation that has been accepted by the Commission in the Company's past rate cases. Purchased power and fuel working capital of $3,593,542 is included separately on Line 10 and was calculated using a lead/lag approach, the details of which are given later in this testimony.

Q: What offsets have you considered in determining the working capital requirement?

A: Lines 12 and 13 of Schedule 6-1 list customer deposits of $1,082,784 and accrued property taxes of $3,031,968 relative to the electric department. Because these funds have been made available for use within the Company, they have been used as offsets to the working capital requirement.

Q: Explain Schedule 6-2 titled "Fuel Stocks – Electric."

A: Schedule 6-2 represents the amount of fuel on hand for each of our existing power plants during each of the 13 months ending August 31, 2010. Line 15 shows the 13-month average of $246,051.

Q: Explain Schedule 6-3 titled "Wholesale Fuels."

A: Schedule 6-3 includes the amount of bulk equipment fuel, by type, held by the Company for each of the 13 months ending August 31, 2010. The amounts represent funds spent that will be utilized for construction and operations in future months. Except for $147 of backhoe diesel fuel, all of the amounts are directly assigned to electric because they are used in the electric operations in Great Bend.

Q: Did you provide the details of the materials and supplies that you have included as requiring working capital?

A: Yes. I have shown on Schedule 6-4 the 13-month average balances of the materials and supplies account that are recorded on the books of the Company. Line 15 shows the 13-month average of $6,392,005 for electric.

Q: Have you provided further detail on the prepaid insurance working capital requirements?

A: Yes. The details for this rate base item are presented on Schedule 6-5. Prepaid amounts for workers' compensation insurance is separated from general insurance because it is allocated to electric and gas by payroll. General insurance is allocated to electric and gas relative to how the premium components were assessed. For example, property damage insurance is allocated by plant in service. I have used the 13-month average methodology in the determination of the appropriate average prepaid amount which should be considered as a rate base component since prepaid insurance varies during the year. The majority of the premiums are paid in March of each year and are amortized to expense over the next twelve months.

Q: Did you compute a cash working capital allowance for the Company?

A: Yes. This amount is shown on Schedule 6-6. I have considered all expenses and have included in Column 5 production, transmission, distribution, customer accounts, customer service, sales and administrative and general expenses for the computation of the cash working capital allowance.

Q: What formula did you use in the computation of the cash working capital requirement on Schedule 6-6?

A: I applied the 12.5 percent or one-eighth method, commonly referred to as the "formula method," to the adjusted total Kansas jurisdictional operating expenses of the Company. The 12.5 percent factor has been applied and used by the Commission for the Company in prior utility rate cases, and is still appropriate for this case. The amounts in Schedule 6-6 represent our electric division's working capital requirements only. Total cash working capital requested is $2,249,378 as shown on Line 14.

Q: Have you included cash working capital for purchased power and production fuel costs?

A: Yes. In Schedule 6-7, I calculated purchased power and production fuel working capital using a lead/lag approach in which I calculated the weighted average days between the time that power and generation fuel is consumed and the time payment is received from customers. From this "revenue lag" time, I subtracted the "expense lag" time, which is the weighted average days between the delivery of power and fuel for customer consumption, and the time payment has been received from us by the suppliers.

Q: How did you calculate the "revenue lag" days?

A: I generated the start and end dates for all nine of our billing cycles as included on Lines 1 through 9 of Columns A through C of Schedule 6-7. From this, the total read days and average read days are calculated. If all meters were read at one point of time, all volumes for a month would be included and would yield an average service period midpoint of 15.2 days (365 days / 12 months / 2) equal to that used for the supplier lag. Because meters within a billing cycle are read over several days, an additional lag is generated equal to the average read days in Column D. The sum of the average read days and the 15.2-day midpoint equals the weighted midpoint of service period in Column G. I then calculated the average bill date for each billing cycle which allowed me to calculate the bill generation lag, or time that lapses between the end of the meter read cycle date and when the customer is billed. On page two, I calculated the collection lag, or days of receivables, utilizing a thirteen-month average of electric receivables and electric revenue billed in the test year. The sum of the weighted midpoint of service period (Column G), billing generation lag (Column I) and the collection lag (Column J) yields the total revenue lag days by billing cycle (Column K), which are then weighted by revenue to calculate the revenue lag. This calculation yields a revenue lag of 51.8 days, as shown on Line 10, Column M of Schedule 6-7, page 1.

Q: Why does Midwest Energy combine its billing into nine groups which causes the read day lag, versus billing daily?

A: Combining billing into nine groups called billing cycles (as opposed to billing daily) improves efficiency for bill calculations performed internally and generates outsourced savings from our vendor who prints and mails the customer bills. These efficiencies and savings have been reflected in our expenses in this rate filing.

Q: How is the supplier lag calculated?

A: Page 3 of Schedule 6-7 shows our monthly billings from our electric suppliers. Though these numbers still reflect billings from the previous rate case, we had no material changes in the billing terms we receive from our suppliers since then. The Company is billed by its suppliers monthly for the purchased power deliveries during each calendar month. We calculated the average bill date, or days following the end of the service month, for each supplier, which is shown on page 1, Lines 11 through 22, column J. On Line 23, we also included the average bill date for the fuel that will be purchased for the GMEC plant. We then added the 15.2 midpoint days of an average month using a 365-day year to yield total lag by supplier and then weighted this by the supplier purchases to yield the combined supplier lag. This lag came to 35.1 days for purchased power and 32.5 days for GMEC fuel as shown on Line 25 of Schedule 6-7, page 1.

Q: How is the revenue and expense lag converted into a rate base amount?

A: The difference between the revenue and supplier lag came to 16.7 days, or 4.56 percent of 365 days, for purchased power and 19.3 days, or 5.3 percent, for GMEC fuel. These percentages are multiplied by the pro forma adjusted test year amounts for purchased power and production fuel costs on Line 28 to yield working capital of $3,593,542 on Line 30.

Q: Does the Company already receive timely recovery of purchased power and fuel since it has an Energy Cost Adjustment (ECA) mechanism in place?

A: No. This was argued by both Staff and CURB in a past electric rate case (Docket No. 08-MDWE-594-RTS) which I addressed in my rebuttal testimony under same docket. In short, the ECA only ensures eventual recovery of costs, not that recovery is timely. Power consumed by customers during a particular month (say, January) must be paid for by the Company to its suppliers by the 22nd of the following month (February). Beginning with the first billing cycle of the next month (March), customers' bills will include the ECA charge to recover costs associated with invoices received in the prior month (February), and power consumed in the month before (January). The

Company is therefore not reimbursed for the power costs for another 24 days (see Schedule 6-7, column J, lines 1 – 10) when bills are due (April). Clearly, there is a lag between payment for purchased power and the time at which those costs are recovered from customers.

Q: How were customer deposit amounts developed on Schedule 6-8?

A: Customer deposits were assigned on the basis of actual amounts shown on Company's detailed customer deposit computer runs. As a result, all amounts are directly assignable between the electric and gas divisions.

Q: Please discuss Schedule 6-9 that relates to accrued property taxes.

A: Schedule 6-9 sets forth the 13-month average balance for the accrued property taxes recorded in Account 236-1. Lines 16 through 18 show the allocation of accrued property taxes between the electric and gas divisions.

Q: How were the accrued property taxes allocated between the electric and gas divisions?

A: Accrued property taxes were allocated on the basis of the actual property tax expense as recorded for the fiscal year and included on Line 16. The Company records property tax expense on a monthly estimated basis and adjusts to the actual tax expense for each division after the tax bills have been received in November of each year.

SECTION 7 – CAPITAL STRUCTURE

Q: Have you computed the capital structures for the Company?

A: Yes. I have computed and shown the capital structure for Midwest Energy on Schedule 7-1. I have itemized the various components of capital as of December 31, 2009 and August 31, 2010. The current capital structure of the Company, after adjustments, consists of 34.78 percent equity and 65.22 percent debt. Included in Column 7 of Schedule 7-1 is the weighted cost of equity and long-term debt which is then weighted to calculate the total rate of return of 6.8953 percent. The capital structure and costs should be updated prior to Commission approval of this application.

Q: Discuss Schedule 7-2 titled "Equity Return Requirement."

A: The purpose of Schedule 7-2 is to show the calculation of the return on equity portion of rate of return using a version of the Goodwin model previously adopted by the Commission for calculating equity costs for cooperatives. For elaboration on this model and the variables used to calculate the return on equity, please refer to Mr. Edward's testimony. The return on equity using this model is 10.1491 percent.

Q: Have you shown the components of the capital structure in other schedules?

A: Yes, I have. Schedule 7-3 details the debt obligations of the Company as of August 31, 2010 that are included in the capital structure and cost of debt portion of the requested return. These debt obligations include our those from our two financial institutional lenders, CFC and CoBank, as well as the funds provided by USDA for the REDL&G program and from KHRC and EK for the How$mart program.

Q: Would you explain Schedule 7-4?

A: Schedule 7-4 shows the computation of the times interest earned ratio (TIER) as well as the debt service coverage (DSC), as adjusted for the test year ended August 31, 2010, the minimum DSC requirement as contained in the NRUCFC and CoBank mortgages, and the TIER and DSC resulting from the proposed rate increase. The margins shown on this schedule on Line 2 and 7, Column 4, are identical to that information shown on Line 25 of Schedule 9-1. The Company is clearly meeting the Debt Service Coverage ("DSC") minimum requirement because the Company took advantage of recent favorable long-term rates for new debt and refinanced debt which significantly lowered the annual principal payments due to our lenders. As long-term interest rates continue to rise, new debt issuances will likely be executed with shorter terms which will increase principal payments. Nevertheless, the Company's proposed DSC level of 1.93 is very close to the national average as shown on Graph 2, page 12 of Mr. Edward's testimony. The Times Interest Earned Ratio (TIER) ignores principal amounts and yields a level of 1.89 after the proposed rate increase. The Company's proposed TIER is below the average coop level as shown on Graph 1, page 12 of Mr. Edward's testimony. The more important ratio is the return on equity ("ROE") which supports the Company's capital structure and is a component of the determined revenue requirement. Again, Mr. Edwards provides testimony supporting the proposed ROE.

Q: What is the purpose of Schedule 7-5?

A: Schedule 7-5 starts with the debt service requirements of the Company from Schedule 7-7 and allocates the amounts between the electric and gas divisions. Annualized interest payments have been calculated as $14,598,102, and principal payments are calculated as $7,927,660 for total debt service of $22,525,762 as shown on Line 3. On Line 7, I have shown the electric portion of annualized interest expense adjustment made for pro forma purposes. This adjustment is shown as a below-the-line adjustment (adjustment #22) on Schedule 9-3 and therefore does not impact revenue requirements. On Lines 8 through 11, I have shown the allocation of debt service requirements between electric and gas. I have allocated the debt service requirements on the basis of the gross plant allocation factor shown on Schedule 12-1 that allocates 84.78 percent, or $19,096,266 to electric.

Q: Have you included a schedule displaying the historical debt service coverage for at least the three calendar years preceding the test year and the test year?

A: Yes. I have included this in Schedule 7-6.

Q: Did you compute or analyze the long-term debt requirements and interest payments for long-term debt that will be made during the twelve month period following the end of the test year?

A: Yes. I have shown this information on Schedule 7-7. Between the end of the test year and December 31, 2010, the Company incurred an additional $20 million of new long-term debt which was added on line 31 in order to calculate the most current debt service. This new debt was <u>not</u> added to the capital structure since the entire capital structure (debt and equity) should be updated at a later point. Total estimated debt service of $22,525,762 will be required in 2011 of which $19,096,266 is allocated to the electric department based on the gross plant allocation factor shown in Schedule 12-1.

Q: Is the Company required to maintain investments with its lenders, NRUCFC and CoBank?

A: Yes. The details of this investment are shown on Schedule 7-8. The total of these investments is $ 12,344,304 at the end of the test year. As shown on Schedule 3-2 and discussed above, we have allocated $10,464,912 of these investments to the electric division based on gross plant in service and included the amount in rate base. Since the investments allocated to electric will earn an estimated $216,331 of interest during the next fiscal year, we have included the income as a reduction to the overall revenue requirement as shown on Line 20 of Schedule 9-1. The annualization of the interest income results in a small pro forma adjustment which shows as adjustment #21 on Schedule 9-3.

SECTION 8 – HISTORICAL INFORMATION

Q: Please discuss Section 8.

A: Schedule 8-1 presents comparative balance sheets of the Company for the end of the calendar years 2007 through 2009 as well as the end of the test year. According to Commission regulations, financial data must be presented for the test period and the three calendar years preceding the test period. Schedule 8-2 presents a comparative statement of operating margins for the Company for years ending December 31, 2007 through 2009 and the test year. Schedule 8-3 presents comparative operating income statements for electric for the years 2007 through 2009 plus the test year. Schedule 8-4 provides a more detailed breakdown of revenue for this time period. Schedule 8-5 provides the detailed breakdown of the various expense accounts for the time period.

Q: Please discuss your Schedules 8-6 and 8-7 that relate to sales, revenue, average revenue per MWh and average number of customers.

A: Schedule 8-6 presents operating statistics, including MWh sales, revenues and average revenue per MWh for each customer class for each of the years ending December 31, 2007 through 2009 plus the test year. Schedule 8-7 provides the number of customers for each customer class as well as the average revenue per customer for the same time period.

Q: Please discuss Schedule 8-8.

A: Schedule 8-8 shows average electric maintenance expense per MWh for the calendar years 2007 through 2009 and the test year period.

Q: Please discuss Schedule 8-9 relating to company salaries and wages.

A: Schedule 8-9 presents a breakdown of salary expense for the electric division by primary classification for the calendar years 2007 through 2009 plus the test year. The calendar year data corresponds with the data presented on Pages 354 - 355 of the Annual Report to the Kansas Corporation Commission.

SECTION 9 – PRO FORMA OPERATING INCOME AND EXPENSES

Q: Please discuss Schedule 9-1, entitled "Summary of Net Margins as Recorded, as Adjusted and Reflecting Proposed Increases."

A: Schedule 9-1 sets forth in summary form the "as recorded", the "as adjusted", and the pro forma cost of service as of August 31, 2010. Net margins are shown on Line 25 for the three presentations.

Q: Please describe Schedule 9-2.

A: Schedule 9-2 provides a summary of the pro forma adjustments and the pro forma cost of service for Midwest Energy for the test year ending August 31, 2010. The adjustments contained in Column 2 are summarized on Schedule 9-3 and will be discussed in detail in the remainder of this section of my testimony.

Q: What is the proposed increase in revenue requested in this proceeding?

A: The proposed increase in revenue shown in Column 4 of Schedule 9-2 is $3,411,024. However, this amount includes the incremental transmission revenue requirement of $130,534 which is recovered through the TFR. Therefore, the proposed increase in this proceeding is $3,280,490 ($3,411,024 – 130,534).

Q: Have you prepared individual adjustments that adjust the historical test year to a pro forma test year?

A: Yes, I have. The adjustments are summarized in Schedule 9-3 and shown in greater detail on various schedules: For adjustments 1 - 14 related to revenue or energy supply costs, see Schedules 9-4 through 9-11 and the testimony of Michael Volker. Adjustments #15, 16, 17, 18, and 19 are detailed in Schedules 3-3, 9-13, 9-14, 9-15, and 10-1, respectively. Adjustments #20, 21, and 22 are shown on Schedules 9-16, 7-8, and 7-5, respectively.

Q: Please discuss Adjustment #15, Other Income shown on Schedule 3-3.

A: As previously mentioned, the income generated from the REDL&G and How$mart programs was allocated between electric and gas by the number of customer meters. We have allocated $107,735 to electric which reduces the need to increase revenues.

Q: Please discuss the payroll adjustment as shown on Schedule 9-13.

A: Page 2 of Schedule 9-13 details the annualization of the payroll for the Company. Line 4 reflects the test year activity of the active employees at the end of the test period utilizing the rates in effect January 1, 2010 for union employees and February 25, 2010 for non-union employees. Line 5 shows a three percent increase in wages and salaries reflecting, in part, terms of an expected new IBEW contract which will impact wages January 1, 2011. Line 11 represents the total annualized payroll charged to electric expense and is carried forward to Page 1. Page 1 of Schedule 9-13 details the test year salaries and wages as recorded and shown in Column 2. The total payroll as recorded and distributed is used to allocate annualized payroll resulting in an increase of $264,809 to electric expenses as shown on line 14 in Column 6.

Q: Please refer to Schedule 9-14 and discuss your medical insurance, pension expense and payroll tax adjustments.

A: Schedule 9-14 shows the medical and pension amounts for the test year as compared to the prior 12 months with the increase used for the employee benefits pro forma adjustment. The payroll tax adjustment adds the company's share of FICA (7.65 percent) associated with the pro forma payroll adjustment.

Q: Have you included costs associated with preparing and filing this application?

A: Schedule 9-15 shows the estimated costs of preparation, discovery and hearing and briefing activities which total $195,000. These costs will be updated as part of the final revenue requirement. We are amortizing rate case expense over three years which has been accepted by the Commission in previous rate proceedings. Since the cost of this rate case is less than the previous electric rate case, this pro forma adjustment results in a decrease to revenue requirement of $55,316.

Q: Explain the second section in Schedule 9-15.

A: The Company is requesting deferred treatment of costs to conduct studies and other costs related to purchased power which total $972,263. We are requesting an amortization period of ten years to recover these costs.

Q: Please explain the charitable donations adjustment shown on Schedule 9-16.

A: This adjustment reduces the amount of charitable donations allocated to the electric division during the test year by 50 percent. This adjustment has also been accepted previously by the Commission.

Q: Please explain the final two adjustments shown on Schedule 9-3.

A: Adjustment #21 includes a reduction to revenue requirement for nominal interest income earned on NRUCFC investments as shown on Schedule 7-8 and discussed above. Adjustment #22 is a below-the-line adjustment to interest expense, thereby not affecting revenue requirement. It is shown here for presentation purposes and affects the TIER and DSC calculations on Schedule 7-4.

SECTION 10 – DEPRECIATION EXPENSE

Q: Please discuss Schedule 10-1.

A: Schedule 10-1 presents pro forma annualized depreciation based on plant in service at August 31, 2010 and the same depreciation rates included in the previous electric rate application resulting from the last depreciation study with two exceptions. The first exception is that this application requests an amortization rate of 5% for Intangibles which are part of Pro forma adjustment (A) discussed above. The second exception relates to the CES project discussed below.

Paul Normand and James Aikman, both of Management Applications Consulting, Inc. (MAC) prepared the depreciation study which used plant balances and depreciation reserves as of December 31, 2006. MAC also prepared the depreciation study that was filed with the electric rate application filed in 2002 and a corresponding gas rate application and was accepted by the Commission. The recent (like the former) study focused on the life, salvage and removal cost characteristics of depreciable electric and gas plant that resulted in average remaining life accrual rates to be used until a subsequent study indicates a need for revision. The reserves were not adjusted as a result of the study; however, depreciation rates in Schedule 10-1 have been adjusted to recover the remaining asset value over the remaining useful life of each asset category on a going-forward basis. Although the depreciation rates proposed by the study were adopted by the Company following Commission approval of its last rate case, the pro forma adjustment (adjustment #19 on Schedule 9-3) shows an increase to depreciation expense of $1,066,583. This is primarily due to the inclusion of depreciation for the CES project discussed above as well as other capital additions between December 31, 2009 and the pro forma test year. The CES project was an addition to common plant further discussed below.

Q: Please explain Schedule 10-2.

A: Schedule 10-2 uses the common plant allocated to electric in Schedule 4-3 and the new rates to calculate common plant depreciation allocated to electric. The CES project is included on Line 4, separate from other computer equipment. The reason for segregating it is the approved depreciation rate for computer equipment is based on a useful life of about only four years. This reflected the fact that, at the time of our last depreciation study, the bulk of the computer equipment that was not depreciated fully was comprised of PCs and other shorter-lived equipment. We estimate the life of the CES software to be seven years. Though this rate is not approved by the Commission as part of a depreciation study, it more fairly represents the useful life of the CES software and recovers the cost over a longer period. The resulting adjustment to depreciation expense is transferred to Schedule 10-1, Line 75 and is included in the total depreciation adjustment (Adjustment #19).

SECTION 11 – OTHER TAXES

Q: Please discuss Schedule 11-1 that relates to other taxes.

A: Schedule 11-1 shows the types of taxes and the amounts paid during the test year. Property taxes are the most significant tax paid by the Company amounting to $4,678,438 for the electric division during the test year period. The payroll taxes are allocated as payroll overhead and included in other expenses or capitalized.

SECTION 12 – ALLOCATION FACTORS

Q: Have you included various allocation factors that you have used in this proceeding for the allocation of various investments, costs, etc.?

A: Yes. I am sponsoring the gross plant in service factors shown on Schedule 12-1. All other schedules in Section 12 are sponsored by Michael Volker. Page 2 of Schedule 12-1 uses gross plant before common plant to allocate common plant between electric and gas, the result of which shows on Page 1, Line 1, Column 2. The gross plant allocation factors are used to allocate debt service and investments in NRUCFC and CoBank. Other allocation factors are derived from values within certain schedules and have therefore been included in those schedules.

Q: Does this conclude your testimony?

A: Yes.