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

**IN THE MATTER OF THE APPLICATION OF
MIDWEST ENERGY, INC. FOR APPROVAL TO
MAKE CERTAIN CHANGES IN ITS
CHARGES FOR GAS SERVICE**

DOCKET NO. 06-MDWG- 1027-RTS

DIRECT TESTIMONY OF

**THOMAS MEIS
VICE PRESIDENT OF FINANCE**

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 of Finance 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 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.

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, Schedule 2, except Schedules 9-4 and 9-5. In Section 7, additional testimony is provided by William Edwards of CFC 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 December 31, 2005 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 December 31, 2005. The Kansas jurisdictional rate base is $41,279,697. Lines 8 through 10 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 11 shows our proposed rate of return of 8.4888 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 December 31, 2005.

Q: Please explain Schedule 3-2.

A: Schedule 3-2 shows customer advances for construction which are amounts provided by customers and are deducted from rate base. As of December 31, 2005, no customer advances are outstanding for the gas division.

Q: Schedule 3-3 details an investment in National Rural Utilities Cooperative Finance Corporation (NRUCFC) 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. On December 31, 2005, the Company had investments totaling $2,258,204 on which the Company receives no return (see Schedule 7-8, Line 6). 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 $7,026,713 for another required investment on which it receives nominal interest income, which has been included as revenue in this application to reduce the overall revenue requirement. This treatment correctly reflects the total costs of obtaining the financing used to construct facilities and provide service to Midwest Energy's customers and was accepted by the Commission in the last rate case. Of the combined investment of $9,284,917, the amount allocated to regulated activities (based on the regulated debt allocation factor in Schedule 7-1) is $8,116,869 of which $1,578,731, or 19.45 percent, was allocated to gas using the gross plant allocation factor (Schedule 12-1).

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 gas plant in service by functional category as recorded and as adjusted at December 31, 2005. No adjustments were made to recorded plant balances at December 31, 2005 except that account 114, acquisition adjustments, has been excluded from the schedule and not included in rate base.

Q: Please discuss Schedule 4-2.

A: Schedule 4-2 provides the balance of the gas plant in service for the calendar years ending December 31, 2002, 2003, 2004 and 2005 by primary accounts. Contributions-in-aid-of-construction (CIAOC) of $3,508,643 were received from Finney County Irrigation Project customers and were used to reduce distribution plant. Line 56, Page 2, shows the amount of common plant assigned to gas based on its share of gross plant in service at year-end. The total gas plant in service for the test year is $58,157,181 as shown on Line 59 of Column 5, Page 2.

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. The totals on Lines 1 through 6 show the total common plant in service on a total company basis. Lines 7 through 10 show the electric and gas percentages of gross plant. Lines 11 through 16 show the amount of common plant allocated to electric, and Lines 17 through 22 show the amounts allocated to gas.

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 gas plant in service as of December 31, 2005. A total reserve balance of $23,799,542 is shown on line 10. Line 11 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 gas plant in service for calendar years 2002 through 2005.

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 $5,343,327 that has been included as a rate base item on Schedule 3-1, Line 4. Lines 1 through 9 present detail on fuel stock, materials and supplies and prepaid insurance that comprise a part of the total working capital requirement amount. On Line 10, the Company has included a cash working capital requirement of $1,328,479 for non-purchased gas O&M using one-eighth of the non-purchased gas O&M expenses, a calculation that was accepted by the Commission in the Company's last rate case. Purchased gas working capital of $1,151,748 is included separately on Line 11 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 13 and 14 of Schedule 6-1 list customer deposits of $226,720 and accrued property taxes of $431,346 relative to the gas 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 – Gas."

A: Schedule 6-2 represents the amount of gas storage on hand for each of the 13 months December 2004 through December 2005. Line 15 shows the 13-month average of $2,979,084.

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

A: Schedule 6-3 includes the amount of bulk fuel, by type, held by the Company for each of the 13 months December 2004 through December 2005. The amounts represent funds spent that will be utilized for construction and operations in future months. Except for $237 of backhoe diesel fuel, all of the amounts are allocated to electric because they are mainly 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 $377,192 for gas.

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 is paid in March of each year and is amortized to expense in 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 the amounts listed in Column 5 for production, other gas production expense, transmission, distribution, customer accounts, customer service, sales, administrative and general expenses, depreciation and taxes other than income in my computation for 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, was accepted in our last rate case and is still appropriate for this case. The amounts on Schedule 6-6 represent our gas division's working capital requirements only. Total cash working capital requested is $1,328,479 as shown on Line 15.

Q: Have you included cash working capital for purchased gas costs?

A: Yes. In Schedule 6-7, we calculated purchased gas working capital using a lead/lag approach in which we calculated the weighted average days between the time that gas is consumed and the time payment is received from customers. From this "revenue lag" time, we subtracted the "expense lag" time, which is the weighted average days between the delivery of gas 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: We generated the start and end dates for eight of our nine billing cycles (billing cycle #5 was excluded because it consists entirely of transportation customers) as included on Lines 1 through 8 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. We then calculated the average bill date for each billing cycle which allowed us 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, we calculated the collection lag, or days of receivables, utilizing a thirteen-month average of gas receivables and gas 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 K) yields the total revenue lag days by billing cycle (Column L), which are then weighted by revenue to calculate the revenue lag. This calculation yields a revenue lag of 49.8 days, as shown on line 9 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 cycles into nine groups 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 gas expense lag calculated?

A: Page 3 of Schedule 6-7 shows our monthly billings from our gas suppliers during the test year. The Company is billed by its suppliers monthly for the gas 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 10 through 21, column K. We then added the 15.2 midpoint days of an average month using a 365-day year to yield total commodity expense lag by vendor and then weighted this by the vendor purchases to yield the combined expense lag. This lag came to 38.6 days as shown on Line 22 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 expense lag came to 11.3 days, or 3.08 percent of 365 days. This is multiplied by the annual purchased gas cost of $37,337,920 on line 27 to yield working capital of $1,151,748 on line 28.

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. The details of this allocation factor are shown on Schedule 12-2. 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 have shown the capital structure for Midwest Energy on Schedule 7-1. I have broken down the various components of capital as of December 31, 2004 and December 31, 2005. The current capital structure of the Company, after adjustments, consists of 39.52 percent equity and 60.48 percent debt, compared to 36.29 percent equity and 63.71 percent debt in 2004. Included in Column 6 is the weighted cost of equity and long-term debt which is then weighted to calculate the total rate of return of 8.4888 percent, which is discussed in Mr. Edward's testimony which supports the capital structure and costs requested in 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 model previously used by the Commission. 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 the model is 13.51 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 December 31, 2005 that are included in the capital structure and cost of debt portion of the requested return.

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 December 31, 2005, the minimum DSC requirement as contained in the NRUCFC mortgage, and the TIER and DSC resulting from the proposed rate increase. The margins shown on this schedule on Line 2 and 7, Column 2, are identical to that information shown on Line 21 of Schedule 9-1. It is clear from the DSC calculations on Line 12 that we are not currently meeting our minimum bank requirement of 1.35. The minimum DSC requirement increased the TIER to 1.24.

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

A: Schedule 7-5 shows the debt service requirements of the Company for 2005 as well as the pro forma interest adjustment. Annualized interest payments for the test year period have been calculated as $8,009,542, of which $7,001,937 relates to regulated operations. Principal payments allocated to regulated operations and due in 2006 total $8,557,185. On Line 9, I have shown the annualized interest expense adjustment made for pro forma purposes. The portion of this adjustment allocated to gas is shown as a below-the-line adjustment (adjustment #22) on Schedule 9-3 and therefore does not impact revenue requirements. On Lines 10 through 13, 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 19.45 percent to gas.

Q: Have you included a schedule displaying the historical debt service coverage for at least the three calendar years proceeding the test year, the test year and the 12-month period preceding the test year?

A: Yes. I have included this in Schedule 7-6 which shows that by 2005 (before adjustments), our debt service coverage decreases to only 0.91.

Q: Did you compute or analyze the long-term debt requirements and interest payments for long-term debt that will be made during the fiscal year ended December 31, 2006?

A: Yes. I have shown this information on Schedule 7-7. Total debt service coverage of $17,514,737 will be required of which $15,311,372 is allocated to regulated operations. Of this amount, $2,978,062 is allocated to the gas department on the gross plant allocation factor shown in Schedule 12-1.

Q: Is the Company required to invest in the NRUCFC?

A: Yes. The details of this investment are shown on Schedule 7-8. Investment in the NRUCFC is $9,284,917 at the end of the test year, of which $8,116,869 is allocated to regulated operations. These investments will earn approximately $192,084 of interest during the next fiscal year, of which $167,920 is allocated to regulated operations. The investments consist of interest bearing loan proceeds investment of $7,026,713 and non-interest bearing patronage term certificates of $2,258,204. Both investments have been included as rate base items. The regulated portion of the interest income has been allocated to electric and gas based on gross plant in service and included as an adjustment to revenues to reduce the overall revenue requirement. 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 years 2002 through 2005. According to Commission regulations, financial data must be presented for the test period, the twelve months preceding the test period and the three calendar years proceeding the test period. Schedule 8-2 presents a comparative statement of operating margins for the Company for years ending December 31, 2002 through 2005. Schedule 8-3 presents comparative operating income statements for gas for the years 2002 through 2005. 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 MMBTU and average number of customers.

A: Schedule 8-6 presents operating statistics, including MMBTU sales, revenues and average revenue per MMBTU for each customer class for each of the years ending December 31, 2002 through 2005. 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 maintenance expense per MMBTU for gas in the years 2002 through 2005.

Q: Please discuss Schedule 8-9 relating to gas division salaries.

A: Schedule 8-9 presents a breakdown of salary expense for the gas division by primary classification for the calendar years 2002 through 2005. The calendar year data will correspond 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 December 31, 2005. Net margins are shown on Line 21 for the three presentations.

Q: Please describe Schedule 9-2.

A: Schedule 9-2 provides the pro forma adjustments and the pro forma cost of service for Midwest Energy for the test year ending December 31, 2005. 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 requested by the Company of $3,420,142 is shown in Column 4 of Schedule 9-2.

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 the following schedules: Refer to Mr. Volker's testimony regarding Schedules 9-4 and 9-5 that relate to revenue and gas cost adjustments (adjustments #1 through 16). Adjustments #17, 18, 19 and 20 are detailed in Schedules 9-6, 10-1, 9-7 and 9-8, respectively. Adjustments #21, 22 and 23 are shown on Schedules 7-8, 7-5 and 9-9, respectively.

Q: Please discuss the payroll adjustment as shown on Schedule 9-6.

A: Page 2 of Schedule 9-6 details the annualization of the payroll for the Company. Line 4 reflects the 2005 activity of the active employees at year-end utilizing the rates in effect January 1, 2006 for union employees and February 26, 2006 for non-union employees. Line 5 shows a 3.5 percent increase in wages and salaries reflecting the rates that will be in effect January 1, 2007 for union employees and February 25, 2007 for non-union employees. Line 11 represents the total annualized payroll charged to gas expense and is carried forward to Page 1. Page 1 of Schedule 9-6 details the 2005 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 $347,975 to gas expenses as shown on line 16 in Column 6.

Q: Discuss the adjustments shown on Schedule 9-7, page 1 and 2.

A: Schedule 9-7, page 1 shows total amounts expended for the 2006 gas rate case as of the end of 2005 and estimated additional amounts for preparation, discovery and hearing and briefing activities. Page 2 shows total costs as of the end of the test year associated with conversion of gas gathering customers to other energy sources which is related to the presence of hydrogen sulfide in the gas. Consistent with the accounting order in Docket No. 05-MDWG-879-ACT, we are amortizing these costs over three years. Midwest Energy has not received fuel conversion invoices for three customers. We expect those projects to be completed so a final amortization can be calculated prior to resolution of this case.

Q: Please refer to Schedule 9-8 and discuss your medical insurance, pension expense and payroll tax adjustments.

A: Schedule 9-8 shows the medical and pension amounts for 2004 and 2005, the increase of which is 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: Please explain the charitable donations adjustment shown on Schedule 9-9.

A: This adjustment reduces the amount of charitable donations allocated to the gas division during the test year by 50 percent. This adjustment has been accepted by the Commission in previous rate proceedings.

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 December 31, 2005 and depreciation rates approved by the Commission in the last rate case. The pro forma adjustment (adjustment #18 on Schedule 9-3) to depreciation expense resulting from annualizing results in an increase of $38,124 as shown on page 2, Line 45, Column 8.

Q: Please explain Schedule 10-2.

A: Schedule 10-2 uses the common plant allocated to gas in Schedule 4-3 and the new rates to calculate common plant depreciation allocated to gas. The amortization of plant acquisition adjustment is also calculated on the December 31, 2005 balances. The acquisition adjustment for gas plant purchased from KN Energy is amortized over 15 years.

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 $696,872 for the gas division in 2005. The payroll taxes are allocated as payroll overhead and included in other expenses or capitalized.

SECTION 12 – ALLOCATION FACTORS

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

A: Yes. I have set forth the various allocation factors and how they were derived in Section 12, as is required by the Commission's filing requirements.

Q: Have you denoted what each specific allocation factor is used for?

A: Yes. I have shown on each schedule in Section 12 where the allocation factors were used in the previous sections.

Q: Please describe Schedule 12-1 and discuss the gross plant in service allocation factor.

A: Using the 13-month average, the last period of which is December 2005, gross plant is comprised of 80.55 percent electric and 19.45 percent gas.

Q: What is the allocation factor used for?

A: This allocation factor is used for:

1. The allocation of debt service.
2. The allocation of investment in NRUCFC.

Q: Please explain the common plant allocation factor shown on Page 2 of Schedule 12-1.

A: This allocation factor uses electric and gas plant in service, less acquisition adjustments and before the allocation of common plant, to allocate common plant between the electric and gas divisions.

Q: Discuss the accrued property tax allocation factor in Schedule 12-2.

A: Because we accrue both electric and gas property taxes in one liability account, we must allocate the account between the divisions using the amounts expensed monthly during the test year.

Q: Does this conclude your testimony?

A: Yes.

STATE OF KANSAS)
) ss.
COUNTY OF ELLIS)

AFFIDAVIT OF THOMAS MEIS

Thomas Meis, being first duly sworn, deposes and says that he is Vice President of Finance for Midwest Energy, Inc., and that the statements contained in the direct testimony which he is sponsoring in this Docket were prepared by him and are true and correct to the best of his information, knowledge and belief.

Thomas Meis

Subscribed and sworn to me this 21st day of March, 2006.

Notary Public

My Commission Expires:

10-4-08

10-4-08