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BEFORE THE

KANSAS CORPORATION COMMISSION

PREPARED DIRECT TESTIMONY OF

MICHAEL J. VOLKER

ON BEHALF OF

MIDWEST ENERGY, INC.

DIRECT TESTIMONY OF MICHAEL VOLKER

Q: Please state your name, position and business qualifications.

A: My name is Michael Volker. I am the Director of Regulatory and Energy Services for Midwest Energy, Inc. ("Midwest Energy" or the "Company") and am responsible for developing gas and electric tariffs including rates, terms and conditions for utility services, managing the energy services activities, measuring customer satisfaction, and developing forecasts. I hold a Bachelor of Science degree in Mineral Economics from Penn State University and a Master of Economics degree from North Carolina State University. I began my career in 1984 as an Economic Analyst with the Federal Energy Regulatory Commission ("FERC"). In 1985, I left FERC and accepted a position with Carolina Power & Light Company ("CP&L") in Raleigh, North Carolina as a Junior Rate Analyst. I remained with CP&L until 1998 holding positions in the Rates and Energy Services, Systems Planning, and Marketing Departments. When I left CP&L in 1998, I was the Director of Market Research responsible for developing all qualitative and quantitative market research and for gathering and disseminating competitive intelligence. In 1998, I joined the Boston Consulting Group ("BCG") as an Energy Researcher in the Americas Energy Practice located in Atlanta, Georgia where I was responsible for disseminating Competitive Intelligence and making related recommendations for Energy Practice clients. I joined Midwest Energy in 1999 as the Manager of Pricing and Market Research. I added additional responsibilities managing the energy services activities and obtained my current title in 2006. In 1999 I was also named an Adjunct Professor of Economics and Finance at Fort Hays State University in Hays, Kansas. As an Adjunct Professor at Fort Hays State, I teach Economics courses on a part-time basis. I have testified before this Commission a number of times on rate-related topics.

Q: What is the scope of your testimony in this proceeding?

A: I am sponsoring the following portions of the Company filing: Section 9 Schedules 4-12, Section 12 Schedules 6 to 9, Section 15, Section 17, and portions of Section 18. In Section 9, I am sponsoring all adjustments to Revenue (Adjustment Numbers 1-7) and to the costs of Energy Supply (Adjustment Numbers 8-14) that are passed on to customers via the Energy Cost Adjustment ("ECA"). I provide several Exhibits in my direct testimony in support of the Weather Normalization adjustment to Revenue and Energy Supply. I also provide an exhibit showing the portion of the test year revenue derived from the Transmission Formula Rate ("TFR") and the test year revenue increase associated with the TFR and thereby not a part of this general rate proceeding. Finally, I add two exhibits that support rate design changes to the residential and small commercial and industrial rates. In Section 12 Schedules 6 through 9, I am sponsoring all functionalization, classification, and customer class allocation factors used in the cost of service ("COS") study and a map of how they are used. Section 15 details the results of the COS study and proposed or designed rate changes. Included is discussion of a change to inclining block rates for residential and small commercial customers. Section 17 provides comparisons of unadjusted, adjusted and proposed revenues. In Section 18, Company witness Patrick

Parke and I jointly sponsor all changes to the tariff sheets. In general, the changes to tariffs that I sponsor are rate design related including rates, energy blocks, and billing demand provisions within the tariffs.

SECTION 9

Q: What adjustments to the COS are you sponsoring in Section 9?

A: I have sponsored all the adjustments (1-14) to the August 31, 2010 test year revenues and energy supply costs.

The Annualization Adjustment to Revenues and Energy Supply Costs

Q: Please explain the Annualization adjustment in Section 9 Schedule 6.

A: An important principle of ratemaking is the correspondence between costs and revenues for the test year. The test year in this proceeding ends August 31, 2010. The purpose of Annualization is to adjust the test year consumption and corresponding booked revenues to reflect the same 12 month period year as the costs recorded for the test period. Both sales and revenue from rates are based on cycle billed data rather than the test year. Essentially, this means that a considerable amount of the revenue or purchased power costs booked in September of 2010 actually corresponds to consumption that occurred in August of 2010. Likewise, revenue or purchased power costs booked in September of 2009 corresponds to a considerable amount of consumption from August of 2009. Schedule 6 illustrates the calculation of the Annualization adjustments.

The adjustment to revenues is calculated in three steps: First, differences in sales volumes booked in the test year and consumed in the test year are estimated. The amount of volume consumed one month but booked the next is estimated by analysis of billing cycles and the average lag between the meter reading date and the billing date (about five days). Typically, the average bill sent each month is based on usage from the tenth day of the prior month through the ninth day of the current month. Assuming linear usage through a month, this means that on average 2/3 of the usage on bills in the current month are based on consumption from the prior month. In Section 9 Schedule 6, test year volumes are adjusted to remove 2/3 of the volume booked in September of 2009, and add back 2/3 of the volume booked in September of 2010. In this way, all volumes consumed in the test year correspond to all volumes booked in the test year. The net adjustment to sales volumes by class of customer is shown in column 5, of Schedule 6. The second step is to identify the rates to price the change in volume in column 5. The rates are the delivery margin and incremental purchased power costs – columns 6 and 8. The final step is to calculate the total Revenue Annualization adjustment. This is the sum of the change to marginal revenue (column 5 times column 6) and the change to purchased power costs (column 5 times column 8). The Annualization Revenue Adjustment (Number 1) is summarized in column 3 of Section 9, Schedule 4.

Just as revenues need to be adjusted to reflect the actual volumes consumed in the test year ended August 31, 2010, so should the costs of providing the changed volumes be adjusted to reflect the days of the test year. While most costs are not meaningfully different on a booked versus a calendar year basis, the costs of Purchased Power are. Purchased Power costs are booked one full month later than when the consumption associated with the costs occurred. Purchase Power costs booked in September of 2010 are for consumption in August of 2010 and belongs in the test year. Purchase Power costs booked in September of 2009 are for consumption in August of 2009 and should not be included in the test year. Therefore, the Annualization Adjustment to Purchased Power costs is simply the difference between Purchased Power costs booked in September of 2010 versus those booked in September of 2009. The Energy Supply Annualization Adjustment (Adjustment Number 7) reflects the adjustment to Purchase Power costs and is summarized on the bottom of Schedule 6.

The Weather Normalization Adjustment to Revenues and Purchased Power Costs

Q: Please explain the weather normalization adjustments in Section 9, Schedule 7.

A: The second adjustment is the Weather Normalization Adjustment. Like the Annualization Adjustment, Weather Normalization is an adjustment to both the revenues received by the Company and to the purchased power costs incurred by the Company.

Q: Why is Midwest Energy proposing the Weather Normalization Adjustments?

A: The purpose of the Weather Normalization Adjustment is to adjust test year revenues and expenses so that the test year accurately reflects the revenues and expenses that would have occurred if the weather had been normal. The revenues and expenses change because the volume of sales changes with the weather. For example, if the test year summer was warmer than normal, there would be more sales of electricity for air conditioning purposes than in a normal year. Both the revenues and the expenses associated with that higher sales volume would need to be adjusted to reflect normal weather. A large portion of revenues are recovered through rates that are based on volumetric charges, therefore revenues vary with the volume of sales. Purchased Power costs vary with the volume of sales as well. However, it is critical to make the weather normalization adjustment to both revenues and costs because a considerable portion of costs associated with utility service are recovered through volumetric rates even though those costs do not vary with the level of consumption. The fact that sales volumes change due to abnormal weather are not reflected equally in changes to revenue and costs make it critically important to adjust for abnormal weather so the test year accurately reflects the expected or normal year relationship between costs and revenues.

A normal year is one in which the actual weather experienced is consistent with the way the weather has been on average for some period of history. In this case, Midwest has averaged weather data based on 30 years of history to develop the estimate of normal temperatures. The weather metrics used in the forecast are heating and cooling degree days ("HDDs" and "CDDs"). Heating and cooling degree days represent a measure of how temperature impacts the demand for electricity.

Q: If the test year is normal, will an adjustment need to be made?

A: No. But typically, no year is normal including this test year, so an adjustment needs to be made to ensure that revenues and costs reflect normal weather. This is particularly important because these rates may be in effect for many years to come. Over time, weather and consumption tend toward normal. If normal weather is not utilized in the calculation of rates then there will be a discrepancy in rates for all years these rates are in place.

Q: Has the Commission approved weather normalization adjustments in the past?

A: Yes. The Commission had approved weather normalizations in a number of rate proceedings both for electric and gas companies.

Q: Please explain how the weather normalization adjustment is done.

A: Weather normalization has four steps:

1) Determine the weather metric and how the metric varies from normal in the test year;

2) Determine the sensitivity of usage to unit variations from normal weather;

3) Apply the sensitivity determined in step 2 to the variation from normal determined in step 1 to determine the variation from normal in test year usage; and,

4) Adjust revenues and costs to reflect the change in usage due to abnormal weather.

Q: What are the weather metrics?

A: The weather metrics are measures of weather that are utilized to determine normal weather and variation from that. In this proceeding, I use HDDs and CDDs.

Q: Where does the weather data come from?

A: The source of the weather data is from the Kansas State University Research & Extension service. Both HDDs and CDDs are measured at the Hays Municipal weather station – an Automated Surface Observation Station ("ASOS") of the National Oceanic and Atmospheric Administration ("NOAA").

Q: Please explain why temperature data was measured at the Hays weather station.

A: Ideally, the best weather station data to use is that which most closely resembles the actual weather experienced by all customers. Midwest Energy's service territory encompasses a very large geographic area that may experience greatly different weather in one location compared to another. Theoretically, matching weather stations within the Midwest Energy service area to sales in the same area would do a better job of explaining heating and cooling related usage variation than just the Hays station. Unfortunately, to use multiple weather stations, one must have some idea of how much consumption is most closely influenced by the weather measured at that station. In other words, usage data needs to be matched geographically to each weather station utilized. Midwest does not have usage information readily available on a geographic basis. The Hays weather data was utilized because it is the location of the highest concentration of customers (residential primarily) whose usage is sensitive to temperature variation. In short, from both an intuitive and statistically measured standpoint, the Hays weather data works very well in measuring usage variation due to temperature. Further, since we are measuring the marginal impact of weather, it seems reasonable to assume that the changes (as measured by the deviations from normal) in the HDDs and CDDs in Hays are likely to be consistent with other parts of the service area even though the absolute measures differ.

Q: Please explain the calculation of the HDD and CDD weather metrics.

A: HDDs are the measure of how cold a day is. They are calculated by subtracting the average of the daily high and low temperatures as measured at the weather station from 65 degrees – the base temperature. The higher the number of HDDs the colder the day and presumably the higher the consumption of electricity for heating or any other purpose sensitive to cold. CDDs are the measure of how hot a day is. They are calculated by subtracting 65 degrees – the base temperature – from the average of the daily high and low temperature.

Q: Please explain how the usage sensitivity to weather is determined.

A: Regression analysis is used to determine the statistical relationship between the weather variables (the independent variables in the regression equation) and the quantity of electricity demanded (the dependent variable).

Q: Please explain how regression analysis works and how it was used in this proceeding.

A: Regression analysis seeks to explain whether changes in one or more variables (independent variables) can explain variation in another variable (dependent variable). In this case the dependent variable is the monthly consumption of electricity for each class of customer. The independent variables are the weather metrics, HDD's, CDD's and the precipitation variable. The use of regression determines the sensitivity of electricity usage to changes in the weather.

The regression equation is:

$$Usage_t = c + \beta_0(HDD_t) + \beta_1(CDD_t) + \ldots + \varepsilon$$

Where $Usage_t$ is the monthly consumption of electricity for the class measured in kWh per month. HDD_t, and CDD_t are the total monthly HDDs and CDDs respectively. The c, β_0 and β_1 are the regression coefficients. The +… after the CDD variable signifies that there could be other variables utilized to explain usage in the regression equation but for the purposes of weather normalization they are not relevant. The constant term, c, indicates how much electricity would be consumed if the HDDs, CDDs and any other variable in the regression equation were all zero. The Beta terms, β_0, and β_1, are the sensitivity terms which measure how much consumption changes if HDDs or CDDs increase by one degree day. The ε term at the end of the equation signifies the error in the regression model.

Q: What estimation method was used to determine the Beta coefficients for the weather variables?

A: Ordinary Least Squares ("OLS") – a basic statistical technique - was utilized to estimate the Beta coefficients.

Q: Does OLS do a good job estimating sensitivity to weather?

A: Overall, OLS does a very good job estimating the beta coefficients and determining sensitivity to weather for those classes of customers that are sensitive to temperature or precipitation. It has been utilized for this purpose in countless dockets for gas and electric utilities both in Kansas and across the country.

Q: Which customer classes had test year usage that was sensitive to weather?

A: The Residential classes, Small Commercial and Industrial, Large Power, and Special Contracts classes were influenced by weather as measured in HDDs. The Residential, Commercial, Large Power, Irrigation, and Wholesale classes were influenced by weather as measured in CDDs.

Q: What were the results of the estimations?

A: Estimation results are summarized in Exhibit __(Volker-1).

Q: Please explain what these numbers mean.

A: The numbers in columns 1 and 3 are the sensitivities of class usage to a unit change in the independent (weather) variable. For example, for the M-System Regular Residential class, an additional Heating Degree Day will mean an additional 5,478 kWh of electricity consumption. Likewise, for an additional Cooling Degree Day, usage in the M Regular Residential class 36,516 kWhs.

Q: What is the T-Stat in columns 2 and 4 of Exhibit__(Volker-1)?

A: The T Statistic is a measure of statistical significance. In other words, are we confident that the actual values of the regression coefficient are significantly different than zero. Or more directly – do the weather variables examined explain variation in the dependent variable (usage)? A rule of thumb is that a regression coefficient is statistically significant if the absolute value of its T Statistic is greater than two. Obviously all the beta coefficients examined have T Statistics with absolute values over two.

Q: Do your regression models provide a measure of the proportion of the variation in the dependent variable explained by the independent variables?

A: Yes. For each class the R square provides a measure of the proportion of the variation in the dependent variable explained by the independent variables. The

Adjusted R-Square values are reported for each class in column 5 of Exhibit___(Volker-1).

Q: What is the total Weather normalization adjustment to sales volumes?

A: Exhibit__(Volker-2) shows how the weather sensitivities were combined with the variance from normal weather to create a class-by-class adjustment to sales volumes. The statistically derived sensitivities are simply multiplied by the test year difference from normal for each of the weather variables to derive the sales volume adjustment for each customer class.

Q: What are the Weather Normalization Adjustments to Revenues and Energy Supply costs?

A: Exhibit__(Volker-3) illustrates the calculation of the Weather Normalization Adjustments to Revenue (Adjustment Number 2) and Weather Normalization Adjustment to Energy Supply Costs (Adjustment Number 9). First, the normalization to Margin Revenue (column 4) is calculated by multiplying the Weather Normalization Volume Adjustment (column 2) times the Average Margin Rate (column 3). The Average Margin Rate represents the unbundled volumetric rates for the distribution and local generation components of Midwest Energy's rates for each customer class. Next, the calculation of the Adjustment to Energy Supply Costs (Adjustment Number 9 – column 6) is calculated by multiplying the same volume adjustment (column 2) times the Incremental Power Cost (column 5). The Adjustment to Energy Supply Costs represents two things: the unbundled production component of Midwest Energy's rates for each customer class and the amount of pass through (ECA) revenue associated with the Normalization. Like all other components in the ECA, this amount is an equivalent component in both Energy Supply Costs and Revenues. The total Weather Normalization Revenue Adjustment (column 8) is the sum of the Normalization to Margin Revenue (column 5) plus the Normalization to Energy Supply Costs (column 7).

Adjustments to Revenue and Energy Supply Costs to Annualize the Cost of Purchased Power Capacity (Adjustment Numbers 3 and 10).

Q: What are the adjustments on Section 9 Schedule 8?

A: Section 9 Schedule 8 is the calculation of Adjustment Number 3 and Adjustment Number 10. These adjustments reflect the annualized cost of purchased power capacity and corresponding Energy Cost Adjustment ("ECA") pass through revenues associated with the Company's new purchased power agreements. These agreements were only invoiced for two months within the test year (July and August, 2010). Since the new capacity agreements are a significant increase compared to those they replaced, purchased power costs embedded in new rates would not accurately reflect actual purchased power costs going forward without these adjustments.

Section 9 Schedule 8 is divided into two pages. The first page shows the calculation of the adjustment made to both revenues and purchased power costs. The second page shows the allocation of purchased power costs to the rate classes.

Q: Explain calculation of the adjustment on the first page of Section 9 Schedule 8.

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A: Page 1 of Section 9 Schedule 8 compares the monthly cost of capacity for the new contracts with those they replaced. The costs for the associated capacity in the month before (June invoice) and the month after (July invoice) the new agreements were in place were annualized in columns (3) and (5) respectively. The difference between the annualized new and old costs is calculated in column (6). Since the test year already includes two months' of the new capacity costs, the annual increase in purchased power capacity costs calculated in column (6) is reduced by multiplying it by ten-twelfth's for the ten months not included in the test year, $13,800,830. The adjustment is applied to both purchased power cost and pass thru (ECA) revenue and does not add to the requested increase in this case.

Q: Explain the second page of Section 9 Schedule 8.

A: Section 9 Schedule 8, Page 2 shows the allocation of the increase in purchased power capacity costs across rate classes. First, in columns (2) and (5), the increase in purchased power capacity costs are allocated to the rate classes as they are recovered currently – through the ECA mechanism. Essentially, this shows how the new capacity costs are being recovered without a general rate proceeding. As mentioned earlier, the increase in capacity costs do not add to the increase requested in this case. They are already being recovered through the ECA. However, how the new costs are recovered changes in a general rate proceeding. Columns (3) and (6) show how the capacity cost adjustment is allocated to the rate classes through the class cost of service study (COS). When the COS is conducted, a different allocation methodology is utilized to allocate the increased capacity costs than how those costs are spread volumetrically via the ECA. Essentially, this page shows how the increased capacity costs are reallocated to the rate classes after a general rate proceeding.

Q: How are increased capacity costs currently recovered through the ECA?

A: Any purchased power and generation fuel costs that are above the amount embedded in rates are recovered through the ECA. The ECA is "unitized" - it is based on a per kWh basis. In other words, the increase in purchased power costs are allocated to the rate classes on an energy basis and the recovery of purchased power costs above those embedded in rates is based on the volume of energy (kWhs) consumed.

Q: How are the purchased power capacity costs allocated to rate classes in the COS of this proceeding?

A: It depends on the type of capacity. The new capacity contracts are separated into a **[redacted]

[redacted]**

It is worth noting how different the allocation of this adjustment is from a volume of energy (as is currently occurring with recovery through the ECA) to the combination of energy and contribution to peak demands as occurs after reallocation of costs through the COS.

Removing Unregulated Power Sales from Revenue and Energy Supply Costs

Q: What is the next adjustment you are sponsoring?

A: The next adjustment is the Adjustment to Revenues Removing Unregulated Power Sales (Adjustment Number 4) and the corresponding Adjustment to Energy Supply Costs Removing Unregulated Power Sales (Adjustment Number 11). The purpose of these adjustments is to remove the cost and revenues associated with unregulated power sales to wholesale customers for retail cost of service purposes.

Q: Please explain how this adjustment is made.

A: Like the Annualization and the Weather Normalization adjustments, this adjustment is reflected in both revenues and purchased power expenses. The adjustment to revenues is straightforward. On line 23 (column 9) of Section 9, Schedule 9, revenues associated with sales of electricity to wholesale customers are backed out of the test year account 447 (Adjustment Number 4) after being adjusted for Annualization (Adjustment Number 1) and Weather Normalization (Adjustment Number 2). The Annualization and Weather Normalization to the Resale classes are shown on Section 9, Schedules 6 and 7. The corresponding adjustment to Purchased Power expense is done similarly. The test year cost of power purchased on behalf of the Resale classes after adjustment for Annualization and Weather Normalization (Section 9, Schedules 6 and 7) is removed from retail revenue requirements. The amount removed from Energy Supply Cost is shown on row 23, column 8 of Section 9, Schedule 9.

Adjustment for Large Customer Addition Outside of Test Year

Q: Explain the calculation of Adjustment Numbers 5 and 12 on Section 9, Schedule 10.

A: Ordinarily, the Company does not make adjustments for increases or decreases in the sales volumes and corresponding revenues or costs attributable to a change in customers. However, in order to accurately reflect the need for revenue relief, it is appropriate to adjust revenues and expenses for the addition of a large customer just after the end of the test year. Adjustment Numbers 5 and 12 adjust revenues and corresponding purchased power costs to reflect the addition of this customer. First, the anticipated load and sales volumes are calculated. Expected annual kWh sales are shown on row 30 of column 5 of Section 9, Schedule 10. Next, the per-unit margin revenue is multiplied by the volumes. Total margin revenue is shown on row 14 of column 3. Similarly, the per unit purchased power cost is multiplied by the volumes to yield both the additional purchased power cost and the pass through revenue associated with purchased power as shown on row 14 of column 5 (Adjustment 12). The total revenue adjustment is the sum of the two parts, margins and purchased power. The total revenue adjustment is shown on row 14 of column 6 (Adjustment 5).

Demand Side Capacity Cost Adjustment to Purchased Power

Q: Please explain Section 9, Schedule 11.

A: Section 9, Schedule 11 calculates adjustments to revenue and purchased power cost associated with expanding the Company's Pump Curtailment Rider program. The Company intends to pass these costs through the Energy Cost Adjustment mechanism. However, if the Commission deems these costs to not be allowable under the ECA tariff, the Company intends to make an expense adjustment (only) that is recoverable through base rates.

Q: Explain the Pump Curtailment Rider.

A: On May 14, 2010, the Company received approval in Docket No. 10-MDWE-601-TAR to implement a demand response pilot program primarily targeting irrigation customers. The approved tariff is called the Pump Curtailment Rider ("PCR"). Under the PCR, the Company interrupts irrigation pump load by dispatch from a third party vendor (M2M Communications, Inc. or "M2M). The Company pays a per kW fee to M2M to install and maintain interruption equipment, operate a network operations center ("NOC"), maintain a website for use by participating customers and the Company, dispatch interruptions, and other services. The fee is based on the connected capacity of the irrigation pumps. In summary, the Company purchases demand response capability from M2M very similarly to how it purchases generation capacity.

Q: Describe the first year of the PCR pilot program?

A: The Company had 1,873 kW of subscribed load under the program in the first year of the pilot, which was limited to W System irrigation customers only. The Company dispatched seven interruptions through M2M that yielded on average about 78 percent of the subscribed load. The results proved the viability of the program and resulted in a reduced summer peak demand for the Company.

Q: Does the Company plan to expand the demand response program?

A: Yes. The Company has filed a request (Docket No. 11-MDWE-552-TAR) to make the PCR a permanent program and expand its applicability to irrigation customers Company wide. A companion filing (Docket No. 11-MDWE-553-TAR) would reopen a frozen irrigation rate schedule applicable to the M System for irrigation customers willing to participate in the Pump Curtailment Rider program. In addition, the Company has signed an expansion of its agreement with M2M to reach an expected total of 7,000 kW of subscribed load for the summer of 2011. The cost of this much demand capability purchased through this program will be $411,250 as shown on row 4, column 3 of Section 9, Schedule 11.

Q: How does this adjustment impact the requested general rate increase?

A: It does not impact the general rate increase as filed. The adjustment is treated as both an increase in revenues and an increase in purchased power costs. The revenue and cost adjustments offset each other. The reason revenue is adjusted is that the Company believes that the purchase of demand response capability is effectively the same as the purchase of peaking capacity and should thereby be recovered through the ECA mechanism. Recovery of purchased power costs do not impact general rate increases since the costs are also treated as a pass through to revenue via the ECA mechanism.

Q: Has the Commission Staff made a recommendation regarding recovery of purchased demand response capability via the ECA mechanism?

A: No. Company and Staff representatives met in November to discuss rate case issues. The Company representatives discussed their intention to file the purchased demand capability costs as recoverable through its ECA mechanism. Staff neither endorsed nor rejected the Company's plan for filing purchased demand response capability through the ECA. Staff did note that Midwest Energy is unique in that it is a cooperative that purchases the majority of its supply resources and that capacity costs are included as part of its ECA.

Q: Do you believe that purchased demand response capability should be included for recovery via the ECA mechanism?

A: Yes. The purchase of demand response capability is done for the same reason as supply resources are acquired – to meet customer requirements. The Company's purchase of demand resources via the PCR is no different than its purchase of supply resources via its purchased power contracts. The capability is owned by someone else, it is paid for on a per kW basis, it is dispatchable as needed, and it is comparably (or favorably) priced compared to the supply resource it replaces.

There are other reasons to include these costs as part of the ECA. First, if demand response capability is embedded (as an expense) in base rates but not included as a purchased power expense, the Company has less incentive to achieve or exceed the capability included herein. In other words, customers may pay for 7,000 kW of demand response capability whether the Company is able to sign up 7,000 kW of demand response capability or not. This leaves customers at risk for unrealized demand response capability expenses. If recovered through the ECA mechanism, customers would only pay for the demand response capability actually achieved and paid for by the Company. Similarly, if the Company is extremely successful at signing up participants, it could be left with unrecovered costs associated with the purchased demand response capability purchased through this program. Purchased demand response capability flowing through the ECA mechanism would allow the

Company to recover these costs. Finally, by not allowing for rapid recovery of purchased demand response capability as occurs through an ECA mechanism, the Company has no incentive to add cost effective demand response between rate cases. One of the principal advantages of demand response capability is that it can be made in relatively small increments and has the potential to be less lumpy in nature than typically large supply resource additions. Thereby, it serves as a valuable method of meeting customer requirements during interim years between supply resource additions or replacements and potentially extending the time between supply resource additions.

Miscellaneous Revenue Adjustment (Adjustment Number 7)

Q: Please explain Revenue Adjustment Number 7, Miscellaneous.

A: On line 21, column 9 of Section 9, Schedule 4, revenues are increased to remove the unbilled revenues from the test year.

SECTION 12 – ALLOCATION FACTORS

Q: Please briefly describe the cost of service ("COS") model and allocation factors in Section 12 of this application.

A: The Cost of Service Model is a proprietary software model developed for the Company in rate filings. The model fully supports functionally unbundled rate designs and uses available Company cost data to develop the unbundled cost by specific function. By functionally unbundled, I mean the complete separation of costs into functional components. Midwest Energy has defined its functional components as: Production, External Transmission, Generation, MWE Transmission, Primary Distribution, Secondary Distribution, and Onsite.

Q: Please define each of those functions.

A: The Production function refers to generation capacity, demand response capability, and energy from non-Company resources. External Transmission refers to non-Company owned transmission expenses. Generation refers to Company owned generating facilities. MWE Transmission refers to the Company owned Transmission system. Primary and Secondary Distribution functions refer to those portions of the Company's Distribution system. Finally, Onsite refers to customer-specific related items such as meters and services.

Q: Please explain how the cost of service model works.

A: The COS model follows the traditional three-step process: functionalization, classification, and allocation. First, all inputs (rate base, expenses, and revenues) are divided into the functional components noted above. Unlike traditional models, the COS model does not depend solely on FERC account codes to functionalize inputs. Instead, the model functionalizes the appropriate account items through the use of allocation factors derived from more detailed information. Once functionalized, items are classified into demand, energy, or customer components. Finally, the classified components are then allocated to customer rate classes based on the cost causing characteristics of each customer class.

Q: What are the advantages of a functionally unbundled cost of service model?

A: For Midwest Energy, this allows for a better separation into the basic components of rates – Energy Supply, Local Generation, Transmission, and Distribution. The Energy Supply component is the cost of securing power for retail customers. Energy Supply is either purchased power costs, the cost of fuel to run Company-owned generation, or purchased demand response capability costs that are passed through directly to customers. This means that on a monthly basis an adjustment is made to rates via the ECA filings for changes in the cost of Energy Supply. The ECA ensures complete recovery (or pass through) of prudently incurred Energy Supply costs by having a true-up mechanism for over or under recovery of these costs. Unlike Energy Supply costs, the other unbundled portions of rates are only adjusted up or down during a general or base rate case such as this proceeding. Since the nature of costs compared to the way they are recovered through rates is very different, it is very important to unbundle rates carefully.

<u>Functionalization Allocation Factors</u>

Q: How are components of the COS allocated to each function?

A: Functionalization is the process of assigning portions of rate base, revenues and expenses to the seven functional components; Production, External Transmission, Local Generation, MWE Transmission, Primary Distribution, Secondary Distribution, and Onsite. Approximately 40 allocation factors have been derived either exogenously to the COS model or within the model itself. The functional allocators are listed in Section 12 Schedule 6 with the percent of the allocation to each of the seven functions.

Q: How are the functionalized components classified?

A: Classification is the process of further breaking down functionalized components into demand, energy, or customer classifications. Approximately 80 classification allocators have been derived either exogenously to the COS model or within it. The classification allocators are listed in Section 12, Schedule 7 with a brief description and the percent allocation to each of the three classifications.

Q: After rate base, expense, and revenue data have been functionalized and classified, how are they allocated to customer classes?

A: Class allocation is the process of allocating classified components to rate classes. Approximately 200 customer class allocators have been derived either exogenously to the COS model or within it. The classification allocators are listed in Section 12, Schedule 8.

In addition, in Section 12 Schedule 9, is a map that summarizes the complete functionalization, classification, and class allocation factors line by line through the COS study. The map is organized with the amount to be allocated and the functional allocator on each page. For each function, the classification allocators are listed. And finally, for each classification in each function, the customer class allocators are listed.

SETION 15 – COST OF SERVICE

Q: Please summarize the results of the COS study.

A: The third and final phase of the COS model – the class allocation phase – is summarized in Section 15, Schedule 1. This schedule shows for each rate class, the line by line results of the pro forma COS study including detailed rate base items, expenses, revenues, net income, and rate of return (ROR) at current rates.

Q: Please explain Schedules 2 and 3 of Section 15.

A: Schedule 2 of Section 15 summarizes the results of the functional unbundling in this model. In this Schedule is shown the rate base, expenses and revenue requirement by each of the seven functions: Production, External Transmission, Local Generation, MWE Transmission, Primary Distribution, Secondary Distribution, and Onsite. Schedule 3 of Section 15 provides the Unit Costs by unbundled revenue function for each rate class. Schedule 3 is particularly useful when different regulatory mechanisms are used to adjust the rates in each function. For example, the unit costs of Production and External Generation are reflected in the embedded power costs in rates and are recovered via the ECA mechanism. Since the Company has a Formula Transmission Rate and Rider, the unit costs for the unbundled transmission function are consistent with the template used to derive the transmission revenue requirement for the formula rate.

The overall revenue requirement by customer class is summarized on line 30 of Section 15, Schedule 2.

General Discussion of Designed Rates and Revenues

Q: Are these the Rate Class Revenue Requirements the Company proposes for each rate class?

A: No they are not. The COS study with equalized RORs is a starting point on how the Company should meet its total revenue requirements, but there are a number of reasons to vary the ROR for each rate class. These include:

1) Different risks associated with serving different classes of customers;
2) Mitigating rate change impacts;
3) Administrative simplicity; and
4) Encouraging energy efficiency.

These issues have been taken into account when designing proposed rates.

Q: Please discuss Midwest Energy's rate design objectives.

A: Midwest Energy has designed rates to meet a number of objectives:

1) The designs must provide enough revenue to allow the company to meet the Company's revenue requirement as derived in the COS model;
2) The designs should move toward the class COS results;
    a. Fixed charges should become a larger portion of the COS fixed charge.
    b. Class ROR should be closer to the System ROR than previous rates.
    c. Avoid negative class RORs.
    d. Practice gradualism when moving rates toward COS results.
3) The designs should simplify administration by combining rates classes where practical;

4) Impacts on classes should be minimized where possible;

5) Designs should be consistent with energy efficiency policy objectives, and

6) Where consistent with cost causation, designs should bring common rate subclasses closer together between the M and W Systems.

Q: Do the recommended rate designs meet all of the Company's objectives?

A: No. Achievement of one objective can compromise the achievement of others. For example, it may be impossible to achieve a positive rate of return and not severely impact a rate class due to the magnitude of the increase required.

Q: Do the recommended rate designs provide enough revenue to meet the System revenue requirement?

A: Yes. Section 15, Schedule 4, illustrates the total proposed functional rates for retail customers. Designed rates in Section 15, Schedule 4 yield revenues within a few dollars of matching the COS based revenue requirement. The total designed revenue is shown in column 1 on line 49 of Schedule 4. Comparing this with line 326 from Schedule 1 (the COS summary output) shows that the designed rates yield revenues that match the COS revenue requirement.

It is worth noting that not all of the required increase in utility revenue is being requested as part of this general rate increase. A portion of the required revenue is also embedded in costs that will be recovered as part of the Company's next TFR filing. Exhibit_(Volker-4) compares the existing TFR retail rates currently in place (2009 test year) and those embedded in the total cost of service associated with the August 31, 2010 test year. Page 1 of the exhibit shows the difference in TFR revenue for each rate class using the adjusted sales of this filing. Pages 2 through 7 are the TFR calculation as it would be for the August 31, 2011 test year. Again, the Company is not requesting an increase in rates associated with the TFR in this docket, but rather, the general rate increase in this proceeding only includes revenues not associated with TFR revenue. Lines 60 through 64 of Section 15, Schedule 4 remove the TFR related increase and show the general revenue increase requested in this filing.

Q: Please discuss how the rate designs bring rates closer to the second rate design objective – moving closer to the COS results.

A: Rates are brought closer to the COS in three ways: First, rates are designed with customer charges that have been increased for a number of classes – especially those that do not have a demand component to their rates. This results in a higher portion of fixed costs to be covered by fixed charges and moves rates directionally toward the COS results. Second, RORs are increasing for each class that are below the System required ROR. Finally, with only a few exceptions, the rate designs yield a positive ROR for all classes. The proposed M System Annual Service and Incidental Irrigation rate subclasses and the W System Residential Peak Demand and Irrigation subclasses yield negative RORs despite proposed general rate increases that are over double the system average percent increase. I believe that further increasing the proposed rates at this time would be overly burdensome to these classes.

The proposed or designed RORs for each class of customer are shown on line 53 of Section 15, Schedule 4. The current RORs by class are shown on line 305 of Section

15, Schedule 1. Under current rates, eight rate classes are yielding negative RORs. While the RORs under proposed rates are moving in the right direction with no need for additional explanation, the objective to recover a higher percentage of fixed costs through fixed charges does. Even under proposed rates, the Company is not close to recovering even two-thirds of its fixed costs through fixed charges. The proposed rates are merely a step in the right direction.

Section 15, Schedule 3, provides the unit cost of service based on the COS study results. Note that on line 46 of this schedule, the total Customer classified costs in dollars per meter per month are well below the proposed or designed customer charges for most classes of customers. Again, the proposed or designed rates go in the right direction since customer charge revenue would increase by a greater percentage than the overall revenue requirement

SECTION 17

Q: Please explain the schedules in Section 17.

A: Section 17, Schedule 1 examines kWh sales volume and revenues as booked in the test year, as adjusted, and as proposed for all rate classes. Revenue is separated into base rate revenue and revenue attributable to the Energy Cost Adjustment. Schedule 2 presents adjusted revenues and proposed revenues, average customers, per unit costs, and nominal and percent increases by customer class.

SECTION 18

CLASS SPECIFIC TARIFF AND RATE DESIGN CHANGES

Residential Tariffs and Rate Design

Q: Please summarize the changes you are sponsoring to the Residential tariffs and rates.

A: First, the residential tariffs include M System tariffs Regular Residential ("M RES"), All-Electric Residential ("M ARES"), the proposed new Residential Peak Demand ("M RES Peak") and the W System tariffs Regular Residential ("W RES") and Residential Peak Demand ("W RES Peak"). In his testimony, Patrick Parke discusses the changes in the availability, applicability, and other provisions of these tariff sheets. Changes I am sponsoring include the rate designs, applicable billing demands, and a few miscellaneous changes related to billed amounts.

Q: Please summarize the rate design changes you are sponsoring to Residential Rates.

A: The proposed rate design in this case represents a major redesign of how revenue is recovered in addition to the level of revenue recovered from residential customers. The design changes include: inclining blocks in summer rather than (or in addition too) declining blocks during the non-summer months, changes in the size of the blocks, and the introduction of a new demand rate option.

Q: Please discuss the size of the first, second and third blocks in residential rates.

A: Currently, Midwest Energy's M System regular residential rate has three energy blocks: (1) the first 300 kWh; (2) the next 450 kWh; and (3) all remaining kWh. These same blocks have been in place for decades and the basis of how they were developed is not known. I propose to change those blocks to: (1) the first 500 kWh; (2) the next 600 kWh; and, (3) all remaining kWh. These same blocks would apply to all residential rate classes except the W System Residential Peak Demand rate and the proposed M System Residential Peak Demand rate. Both the peak demand rates would only have a single block for all kWh consumed.

Q: What is the basis for changing the residential blocks?

A: The first energy block should represent the most basic electricity consumption needs for the average residential customer. Practically speaking, this means the per customer usage that is not tied to weather, income, or other economic drivers of electricity usage. From a statistical standpoint, this first block is defined by the constant or "c" term discussed in the regression equations used under the weather normalization adjustment section of my testimony. All three residential classes without a peak demand charge are consistent in that the base usage is close to 500 kWh per customer per month. Column 1 of Exhibit_(Volker-5) shows the constant term from the same regression equations used to derive the weather sensitivity discussed in the Weather Normalization section for these three rate classes.

The second block of energy can be thought of as average air conditioning load in the summer months. The amount of this block is determined by examining the average air conditioning load that applies during the summer months (when the block applies). Based on Hays 30-year normal CDDs, the July, August and September CDDs are shown in column 2 of Exhibit_(Volker-5). These are multiplied by the sensitivity per customer per CDD from the same regression equations used to derive the Weather Normalization adjustment. The sensitivities are shown on column 3, and the product of the CDDs times the sensitivities are shown in column 4. Since this represents the cooling over three summer months, the totals in column 4 must be divided by three to show the average summer month cooling load for the three months of approximately 600 kWh shown in column 5 of Exhibit_(Volker-5). The third block is the remaining kwhs consumed in the summer months.

Q: Are the blocks any different for the M System All-Electric Residential Rate than the regular residential rates on the M and W Systems?

A: Yes, but only slightly. For billing convenience, I wanted to keep a total of no more than three blocks per residential rate schedule. But, it is also clear that M ARES customers typically use considerably more electricity during off- peak months for electric heating load. A discount for off-peak heating load is consistent with current rate design and is consistent with an efficiency incentive to encourage geothermal space heating which results in extremely efficient heating and cooling. In order to achieve both billing simplicity while maintaining current winter declining blocks, blocks were established such that there are two in the summer and two in the non-summer months. The first block is the combination of blocks one and two (1,100 kWh) from the regular residential rate. Conceptually, it can be thought of as the base and average space conditioning use. Block two only applies in the non-summer months and is all kWhs greater than 1,100 per customer. It can be thought as non-summer extra use including space heating. Block three only applies in the summer months, and is likewise all kWhs greater than 1,100 per customer. It can be thought of as extra summer usage – in particular air conditioning.

Q: Discuss the change to inclining block rates in the summer for some of the Residential Rate Classes.

A: First, it should be noted that the inclining blocks only apply to the MRES, WRES and ARES rates (99 percent of the Company's residential customers). They do not apply to the WRES Peak of the proposed M System Residential Peak rate. Currently, the Company's summer residential energy rates have only a single (flat) block wherein all kWh are priced the same. In order to recognize that long run utility costs are rising, I believe it is appropriate to send a conservation signal via higher prices during high-use periods. The recent increase in purchased power capacity costs are telling. Essentially, the new contracts doubled the Company's purchased power capacity costs. Further, transmission system capacity costs climb significantly each year as evidenced by annual increases in the Company's Transmission Delivery Charge rates. Finally, recent policy directives have encouraged rate designs that encourage energy efficiency. With that background, I have attempted to design residential energy rates that meet the Company's rate design criteria.

Q: Do the inclining block designs meet the Company's rate design criteria?

A: No design can simultaneously meet all the criteria. I have already mentioned the energy efficiency goal for rate designs, however it is worth discussing each of the remaining objectives to understand how well the designs work.

Q: Do the inclining block designs meet the revenue requirements of each rate class?

A: As shown on line 58 of Section 15, Schedule 4, the RORs for the three rate classes are all below the system average ROR requirement. However, all three rates at least have a positive ROR. The new rates represent an increase over existing rates and thereby bring each of the rate classes closer toward the system average ROR.

Q: Do the inclining block designs move toward the class COS results?

A: Yes they do. For example, all three classes increase customer charges proportionally more than other aspects of rates. Therefore, the fixed charge is becoming a larger portion of the COS fixed charge. Further, I've already discussed that the new rates produce positive RORs albeit lower than the system average.

Q: Are the inclining block designs easy to administer?

A: Yes they are. Most of the Company's residential customers already have three rates blocks. From an administrative standpoint, fewer blocks make administration easier. Whether the blocks are inclining or declining does not really matter. By keeping the number of blocks the same, the administration is not complicated any with the new design.

Q: Are the impacts on customers minimized?

A: Yes they are. First, relatively few customers face significantly higher bills due to the inclining summer block designs. I tested a change in rate design for all three residential classes with inclining block rates. The results of my tests are summarized on Exhibit_(Volker-6). To conduct this test, I took a sample of customer data from each of the rates (MRES, ARES, and WRES). I compared the actual monthly bills for 2009 under the existing rates versus what the bills would have been with the new blocks and inclining summer block design. The rates under the new design were forced to create revenues that were equal to the current rate design for the total sample. However, consistent with the proposed rates, I used the new blocks and the same increases in the summer rates.

There were 2,639 total residential customers sampled across all three rates (row 4, column 1 of Exhibit_(Volker-6)). The total rate revenue calculated from the samples is less than one-tenth of one percent different using either rate design (row 4, column 4). Individually, only 93 (3.5 percent) of the 2,639 customers faced annual bills that were greater than five percent more under the new rate design than using the current design. A slightly larger percent (about 5.4 percent) of the sampled customers would experience annual bills reductions of five percent or more under the new rate design. This test provides very strong evidence that the rate design itself will not cause significant negative impacts on customers' annual bills.

Q: Although relatively few customers are impacted negatively by the new design, do negatively impacted customers have any way to minimize the impact?

A: Yes. Intuitively, the customers that are most likely to face increases are those that use a lot of energy – particularly in the summer. In some instances, the high use may not be attributable to just air conditioning summer load but may represent higher use year around. These customers may benefit by utilizing residential peak demand rates. The design of the W RES Peak and the proposed new M RES Peak does not penalize a residential customer for being a nominally large user – over 1,100 kWh in the summer in particular - but rather is driven by load factor – the measure of how efficiently a customer of any size utilizes energy.

Q: Discuss the proposed Residential Demand rates.

A: The Company already has a residential peak demand rate available for W System customers (W RES Peak). In this filing, the Company is proposing an M System residential demand rate option, the M RES Peak. One of the principle design differences of the Peak Demand rates versus the other residential rates is that the other rate classes tend to penalize customers for being relatively large within the class. With inclining summer blocks – higher rates become a larger portion of a nominally larger customer. The designs of the W RES Peak and the proposed M RES Peak does not penalize a residential customer for being a nominally large user – over 1,100 kWh in the summer in particular - but rather is driven by load factor – the measure of how efficiently a customer uses energy. In particular, relative to the summer peak demand, how much energy does the customer consume? Lower peak demand relative to the total energy consumed by the customer results in more efficient use of resources and will correspond to lower average rates. Again, this means that larger but resource-efficient residential customers that may face higher bills under the inclining block designs may have lower bills under the demand rates.

Q: In general, how well does the proposed W RES Peak rate meet the rate design objectives of the Company?

A: The W RES Peak is one of four rate classes where the proposed rates still yield a negative ROR. However, the proposed increase to this rate class is one of the highest increases both nominally or as a percentage. The original design of the rate precedes the Company's ownership of the W System and may stem back decades. The proposed design goes part of the way toward meeting rate design objectives, but in the interest of avoiding rate shock to the customers currently on the W RES Peak, I am not increasing the rate as much as it should be increased to achieve an acceptable ROR.

Q: Discuss the residential peak demand rates in terms of Patrick Parke's testimony regarding the definition of a residential customer.

A: As addressed by Patrick Parke, in order to avoid providing an incentive to a customer to be classified incorrectly as either residential or general service, the rates for equivalently sized customers need to be similar if not the same. To that end, I have proposed residential rates that are moving in the direction of their general service rate counterparts. On the M System, standard residential and general service small customer rates already share very similar design and will be even closer under the proposed rate designs. However, for large residential customers, the proposed new M RES Peak rate will also be similar to the M System Medium General Service rate. This is significant because (per Patrick Parke's testimony), the proposed M RES Peak rate is mandatory for residential customers over 25 kW in size as is the Medium General Service rate for all general service customers over 25 kW in size. Similarly, on the W System, the WRES rate design is very similar to the W System General Service rate for small customers. The W System General Service rate design changes as the customer grows larger. The rate components of the W RES Peak rate are similar to the components of the W System General Service rate for larger customers.

<u>Small Commercial and Industrial Tariffs and Rate Designs</u>

Q: Please summarize the changes you are sponsoring to Small Commercial and Industrial rates and tariffs.

A: The tariffs included in the Small Commercial and Industrial classes are the M System tariffs General Service Small ("GSS"), General Service Small Demand Rate ("GSS-DR"), Medium General Service ("MGS") and the W System tariffs General Service ("WGS"), and Service to Schools ("WPS"). Additionally, the Annual Service ("AS") tariff, which Patrick Parke proposes to expand to Company-wide rather than just the M System, is included in this group.

Q: Please summarize the rate design changes you are sponsoring to Small Commercial and Industrial Rates.

A: In addition to changing the level of rates for all the rate classes, I have made significant rate design change to the GSS rate including changed blocks, a move to inclining summer blocks rather than declining winter blocks. Like with the residential classes, this is a major redesign of how revenue is recovered in addition to how much revenue is recovered from these customers. I am making minor changes to the WPS rate to simplify administration and help make the rate easily understood by customers.

Q: Please discuss the design changes to the GSS rate.

A: Currently, Midwest Energy's GSS rate has three declining rate energy blocks: (1) the first 200 kWh; (2) the next 800 kWh; and (3) all remaining kWh. In the summer, all kWh are priced at the first (highest) block rate. These same blocks have been in place for decades and the basis of how they were developed is not known. I have proposed to change those blocks to three increasing rate energy blocks: (1) the first 500 kWh; (2) the next 600 kWh; and, (3) all remaining kWh. In the non-summer months, all kWh are priced at the first (lowest) block rate. I believe these blocks are appropriate for use with this rate class because the annual use per GSS customer is less than four percent different than the average residential customer use.

Q: Do the change in blocks severely impact many customers?

A: No they do not. First, relatively few customers face significantly higher bills due to the inclining summer block designs. In the same way I tested the residential block changes, I also tested the block changes to the GSS rate. The results of my tests are summarized on Exhibit_(Volker-6). To conduct this test, I took a sample of customer data from the GSS rate (MRES, ARES, and WRES). I compared the actual monthly bills for 2009 under the existing rates versus what the bills would have been with the new blocks and inclining summer block design. The rates under the new design were forced to create revenues that were equal to the current rate design for the total sample. However, consistent with the proposed rates, I used the new blocks and the same increases in the summer rates.

For the GSS rate, there was 654 customers sampled (row 6, column 1 of Exhibit_(Volker-6)). The total calculated rate revenue from the sample using the new rate design is less than one dollar different from the calculation under the current rate design (row 6, column 4). Only 40 (6.1 percent) of the 654 customers faced annual bills that were greater than five percent more under the new rate design. Further inspection of the sample shows that no customers faced bill increases greater than 9.2 percent attributable to the new rate design. In addition, all 40 of the 40 sampled customers that faced bills bill increases greater than five percent due to the rate design were very large relative to the rate class. The smallest of the 40 was triple the size of the average GSS customer. With the inclining block summer rates, these larger customers could benefit on the GSS-DR.

Q: Please discuss the rate design changes to the W System Public School Rate.

A: I am proposing to make two changes to the WPS (Public School) rate. The first change removes the provision in the rate that increases the size of the first (highest cost) block. I am removing this provision to the rate for three reasons: First, the provision unnecessarily complicates the rate structure and makes it difficult for customers to understand. Approximately five of the 38 customers on this rate are impacted and only slightly. By removing the provision, the net impact is a decrease in the bill size for the larger WPS customers. The remaining customers are not impacted by the change. The second reason I am removing the provision is the small volume of kWh impacted by this provision. This only impacts customers larger than 50 kW in size, and only during the billing months of July, August, and September. In general, only one monthly bill (September) is impacted for schools (and only for the few larger schools) – since school load is generally small for the billing months of July and August. Finally, I am removing this provision because the incremental change in rate - $0.004 per kWh – will not make a meaningful difference in revenues billed for this class on the small increment of kWhs. The benefits of rate understandability and ease of administration far outweigh the minor amount of increased revenue brought about by the provision.

The second change I am proposing to the WPS rate removes the discount provision associated with connected electric heat load. None of the WPS customers are utilizing this provision of the rate. Further, the provision (like the first), is not easy to understand or administer. Again, the benefit of rate understandability and ease of administration far outweigh any potential benefit from the provision.

Q: Are there any other rate design or tariff changes to the Small Commercial and Industrial rates?

A: Any other changes to these tariffs are discussed in the testimony of Patrick Parke.

Q: Do the proposed Small Commercial and Industrial and Industrial rates meet the Company's revenue requirements and move closer to the COS?

A: Three of the rate subclasses (GSS-DR, MGS, and WPS) meet or exceed the Company's revenue requirements and three do not (AS, GSS, and WGS). Only the

AS rate has a negative ROR (slightly), and I did propose an increase to the AS rate that is over two and one-half times the system average rate increase. In addition, I proposed customer charge increases of at least ten percent to four of the six subclasses, meaning most of the subclasses are recovering a greater portion of their fixed costs through fixed charges.

Large Commercial and Industrial Tariffs and Rate Designs

Q: Please summarize the changes you are sponsoring to Large Commercial and Industrial tariffs and rates.

A: The tariffs included in the Large Commercial and Industrial classes are the M System tariffs General Service Large ("GSL"), General Service Large Time of Day ("GSL-TOD"), General Service Heating ("GSH"), and Transmission Level Service ("TLS") and the W System tariff Large Power Contract Service ("WLP"). I am sponsoring the level of rates for these subclasses and minor language changes to the tariff sheets that impact the level of revenue recovery (Minimum Bill provisions in particular). There are no major rate design changes for any of these rates.

Q: Discuss how well the proposed level of rates meets the Company's objectives.

A: As a group, the five rate subclasses meet or exceed their revenue requirements. Two of the subclasses (GSL-TOD and WLP) have rates of return that are positive but below the system average ROR. For both of these classes, the general increase I am proposing exceeds the average system increase by at least a factor of three. For the other three subclasses (GSL, GSH, and TLS), I have proposed very small (less than the system average) but positive increases in base rates despite the RORs all being considerably above the system average. Further, I have proposed increases in customer charges that are proportionally above the proposed increase for each subclass except the TLS rate. The TLS rate already has a customer charge that more than recovers the fixed costs associated with the rate. In summary, the proposed rates bring the RORs closer to the system average for all the subclasses, increased the proportion of fixed charge cost recovery, avoided rate shock, and brought rate designs closer across systems.

Oil Field Tariffs and Rate Designs

Q: Please summarize the changes you are sponsoring to the Oil Field rates and tariffs.

A: The tariffs included in the Oil Field classes are the M System tariff Oil Field Service ("OFS") and the W System tariff Oil Field Service ("WOS"). The M System Small Oil Field classes share common rates with the M System General Service Small rates. I am sponsoring the level of rates for these subclasses and minor language changes to the tariff sheets that impact the level of revenue recovery (Minimum Bill provisions in particular). The only rate design change in this class changes how the billing demand is calculated for the WOS rate. A summer demand ratchet has been added billing demand calculation provisions. Since oil field service is characterized by high year around usage (high load factor), the summer ratchet will not have a substantive impact on revenue determination for this class. Adding the demand ratchet does make the rate consistent with provisions in rates for other like-sized customers.

Q: Discuss how well the proposed level of Oil Field rates meets the Company's objectives.

A: Both Oil Field rates meet or exceed their COS revenue requirement. The OFS rate on the M System very significantly exceeded the system average ROR and therefore I only proposed a very small but positive increase to this rate. The WOS subclass exceeded the system average ROR because I proposed a general rate increase that was considerably above the system average. In general, service to oil field customers is perceived to be of higher risk than most other customer classes due to volatile nature of crude oil prices. For this reason a significantly higher than average price increase was warranted for the WOS class. I also believe that the M and W Oil Field classes have no real cost-based differences (as supported by the Unit Cost of Section 15). Rate designs for these classes should be very similar. Although the proposed rate design does not bring rate parity, it moves the rates in that direction.

<u>Irrigation Tariffs and Rate Designs</u>

Q: Please summarize the changes you are sponsoring to the Irrigation tariffs and rates.

A: The tariffs included in the Irrigation classes are the M System tariffs Incidental Irrigation – Annual Service ("IGI-A"), Irrigation Service – Frozen ("IGF"), Irrigation Service – Time of Day ("IG-TOD"), and the W System tariff Irrigation Service

("WIR"). I am sponsoring the level of rates for these subclasses and minor language changes to the tariff sheets that impact the level of revenue recovery (Minimum Bill provisions in particular). The only rate design change I proposed for this class in a change in how the billing demand is calculated for the WIR rate. This is significant, since the Irrigation Class is characterized by very heavy summer usage and almost no usage during non-summer months. In addition, changes to the IGF rate have been proposed and are before the Commission in Docket 11-MDWE-553-TAR.

Q: Please discuss the change to the WIR billing demand calculation.

A: Currently the WIR rate bases billing demand on the average kilowatt load during the thirty minute period of maximum use during the month. For W System irrigation customers, this generally means significant billing demand during the irrigation season summer months and very little billing demand during the non-summer months. This practice leaves little incentive for irrigation customers to conserve during peak periods and is inconsistent with irrigation rate designs on the M System. Customers in the WIR subclass paid average rates in the test year that were over 50 percent below their comparable rate subclass on the M System (IGF). The resulting COS shows the WIR subclass to have the second lowest ROR of any rate subclass. The proposed design adds a provision in the calculation of billing demand that will base the monthly billing demand on the higher of the current month demand or the demand from the most recent July, August or September billing period. This is will make the calculation of billing demand the same for customers on the WIR and IGF rates.

Q: Will this result in much higher demand charges to WIR customers during non-summer months?

A: Yes, at least somewhat. Not surprisingly, demand billing determinants will almost triple for the average WIR customer. However, I have proposed lowering the demand charge by almost 40 percent. The combined lower demand charge with higher billing determinants will result in higher demand charges, but spread out over all twelve months rather than just in the summer.

It is also worth noting that in 2010 the Pump Curtailment Rider ("PCR") was offered as a pilot program to WIR customers. The Company has filed in Docket No. 11-MDWE-552-TAR to expand and make permanent the PCR across the service area. Participating WIR customers could potentially offset all or most of the increase in demand charges through participation in this voluntary Demand Response program.

Q: Discuss how well the proposed level of Irrigation rates meets the Company's objectives.

A: None of the irrigation subclasses proposed rates yield the COS revenue requirement. Further, only two of the four subclasses have a positive ROR under proposed rates. Although the AS and WIR classes have proposed increases above the system average, the other two classes (IGF and IG-TOD) are below. Although the gap between the similar rate subclasses on the M and W systems has been narrowed, the failure for proposed Irrigation rates to approach most Company rate design objectives warrants further explanation.

Section 9, Schedule 8 (page 2) provides valuable insight to cost issues faced by the Irrigations subclasses. Columns (2) and (5) of the sheet, show the impact of the new purchased power capacity contracts on the various rate subclasses prior to the reallocation of the purchased power capacity. For example, the M System Irrigation subclasses would have paid about $587k (column 2, row 26) of the $13.8 million adjustment for the additional capacity while paying for it thru an ECA adjustment. However, after reallocation through the COS, considerably more of the $13.8 million is properly allocated to the irrigation subclasses. The M System irrigation subclasses are reallocated almost $1.2 million of the capacity cost adjustment (column 3, row 26) after the COS. A pro forma test year is based on the reallocated and annualized upstream capacity costs. Therefore, essentially, the irrigation classes faced a significant increase in their allocated costs just creating the pro forma test year. To a large degree, this explains why for now, I have accepted RORs for the irrigation subclasses that are considerably below the system average.

Q: Explain the general rate decrease you have proposed for the IGF rate.

A: I have proposed a small decrease in rates to the IGF class to bring it closer to the IG-TOD rate. I have done this to prevent customers from being discouraged from switching to the IGF rate from the IG-TOD rate upon approval from the Commission of Dockets No. 11-MDWE-552-TAR and 11-MDWE-553-TAR. A provision of reopening the IGF tariff is that both new irrigation customers and those transferring from the IG-TOD rate must participate on the PCR. IG-TOD customers are not eligible because the rate is designed with no demand charge and as such the logic of offering a demand response incentive is somewhat skewed. Further, the PCR has proven to be successful through the pilot as a demand response program capable of lowering the overall costs of meeting customer capacity requirements. Therefore, I believe keeping the IGF rate comparable with the IG-TOD rate will provide (along with the terms of the PCR) the appropriate incentive for customers to switch from the IG-TOD to the IGF and respond accordingly to the PCR incentives for demand response.

Lighting Tariffs and Rate Designs

Q: Please summarize the changes you are sponsoring to the Lighting tariffs.

A: The tariffs included in the Lighting classes are the Company-Wide tariffs for Leased Area Lighting tariff ("LAL"), Street Lighting ("SL"), and Special Street Lighting ("SSL"), and the W System tariffs Private Areal Lighting ("WPAL"), and Street Lighting ("WSL"). I am sponsoring the level of rates for these subclasses. I have proposed a five percent increase across the board to all rate components in this class and updates to how power is priced for non-standard lamps.

Q: Explain why you have proposed an across the board, five percent increase for these tariffs.

A: The Company's prices for leased area lighting and street lighting have not increased in decades. In fact, lighting rates have effectively declined a number of times with rebased ECA's and other rate changes. With no rate change in this proceeding, lighting rates would again effectively decline as the ECA is rebased. Although the

Lighting classes yield higher than average RORs, I have tried to include all classes with some increase and thereby have spread the total system cost increases at least somewhat across the Lighting classes too.

It is also worth noting that Lighting service is more of an end use product that most customers have deliberately chosen to buy on a bundled basis. Functionally, this COS study does not unbundle end uses.

The ROR for Lighting is above the requested overall system ROR – thereby reducing required revenues from other classes. However, costs have changed between lighting system components in recent years. Further, environmental issues continue to make the availability of mercury vapor lighting problematic. These issues need to be addressed – but not in the context of a general rate proceeding. The Company proposes to conduct a more detailed study of this class before making any relative changes to the various lighting components. By capturing an across the board increase during this proceeding, the Company can file a revenue-neutral detailed cost study that can evaluate current lighting offerings, update pricing of existing offerings to be more reflective of current costs, update offerings to reflect new technologies, cancel offerings that are no longer viable due to environmental concerns or technological obsolescence, and assess the overall impacts on revenues. Since the study will be done outside of the context of a general rate increase, any changes to the lighting billing determinants will be revenue neutral.

Addition Tariff Sheet Changes in Section 18

Q: Are you sponsoring changes to the Master Tariff in Section 18?

A: Yes, I am sponsoring the changes to the Master Tariff that are reflective of the proposed rate design for retail rates in Section 15, Schedule 4. The Master Tariff has changed in a number of ways. In particular, W System rates will be included on the Master Tariff and they will be removed from the individual tariff sheets.

Q: Are you sponsoring any other changes to the tariffs in Section 18?

A: Yes, I am sponsoring the changes to the ECA tariff sheets.

Q: What changes have you proposed for the ECA?

A: First, I have proposed changes to the ECA base based on the COS data from Section 15, Schedule 1. Second, I have proposed language that allows purchased demand response capability costs to be included in the ECA calculation. Finally, I have proposed to make improvements in the ECA methods that will provide customers better and more advanced information regarding the ECA that will be on their bills. Theses ECA changes were originally proposed in Docket No. 10-MDWE-569-TAR, but in agreement with Staff, the Company withdrew the docket such that a new ECA base could be set within the context of a general rate proceeding.

The proposed ECA tariff modifications provide for the following:

1. A quarterly forecast of ECA values.
2. Protection for all parties from excessive over or under recovery of purchased power costs.
3. Continued monthly reporting of actual costs and costs recovered.

4. Better price signal for customers such that a more educated and predetermined electric usage decision can be made.

Q: Does this conclude your testimony?

A: Yes.

MIDWEST ENERGY, INC.
TEST YEAR ENDED AUGUST 31, 2010
WEATHER NORMALIZATION STATISTICAL ESTIMATION SUMMARY

System	Customer Class	HDD Sensitivity[2] kWh/HDD (1)	T-Stat (2)	CDD Sensitivity[1] kWh/CDD (3)	T-Stat (4)	Adjusted R-Square (5)
M System	Regular Residential	5,478.0	15.8	36,516.4	41.9	96.33%
	All Electric Residential	989.3	42.7	1,098.7	18.2	95.85%
	Small C&I Small	1,380.4	8.7	5,681.3	13.9	98.34%
	Small C&I Large			6,592.0	14.1	98.54%
	Large Power			1,611.5	15.3	79.01%
	Special Contract	674.8	6.6			70.25%
	Irrigation			19,863.6	8.9	98.24%
	Wholesale			6,581.1	15.5	79.90%
W System	Regular Residential	2,092.1	14.8	11,214.4	29.2	94.55%
	Peak Residetnial	341.2	27.5	520.9	19.0	93.25%
	Small C&I Small	448.4	2.1	3,236.7	5.9	97.36%
	Small C&I Large			0.0	3.3	96.79%
	Large Power	487.0	2.1			97.79%
	Irrigation			4,811.6	6.4	93.55%
	Wholesale	1,525.8	6.1	3,982.7	5.8	77.83%
	Total System	13,417		101,711		

1. CDD Sensitivity defined - for an average daily temperature change of -1 degree farrenheit, energy usage changes by the listed amount.

2. HDD Sensitivity defined - for an average daily temperature change of +1 degree farrenheit, energy usage changes by the listed amount.

Exhibit__(Volker-2)

MIDWEST ENERGY, INC.
TEST YEAR ENDED AUGUST 31, 2010
WEATHER NORMALIZATION VOLUME ADJUSTMENT

System	Customer Class	HDD Sensitivity kWh/HDD (1)	Abnormal HDD's (2)	HDD Adjustment (kWh) (3)	CDD Sensitivity kWh/CDD (4)	Abnormal CDD's (5)	CDD Adjustment (kWh) (6)	Total Weather Normalization Volume Adj. (kWh) (7)
M System	Regular Residential	5,478.0	(425.8)	(2,332,423)	36,516.4	(96.5)	(3,522,612)	(5,855,034)
	Electric Residential	989.3	(425.8)	(421,239)	1,098.7	(96.5)	(105,990)	(527,229)
	Small C&I Annual		(425.8)			(96.5)		
	Small C&I Small	1,380.4	(425.8)	(587,772)	5,681.3	(96.5)	(548,055)	(1,135,827)
	Small C&I Large		(425.8)		6,592.0	(96.5)	(635,912)	(635,912)
	Transmission Level		(425.8)			(96.5)		
	Large Power		(425.8)		1,611.5	(96.5)	(155,454)	(155,454)
	Special Contract	674.8	(425.8)	(287,333)		(96.5)		(287,333)
	Oil		(425.8)			(96.5)		
	Irrigation		(425.8)		19,863.6	(96.5)	(1,916,179)	(1,916,179)
	Incidental Irrigation		(425.8)			(96.5)		
	Lighting		(425.8)			(96.5)		
	Wholesale		(425.8)		6,581.1	(96.5)	(634,855)	(634,855)
W System	Regular Residential	2,092.1	(425.8)	(890,769)	11,214.4	(96.5)	(1,081,813)	(1,972,582)
	Peak Residetnial	341.2	(425.8)	(145,275)	520.9	(96.5)	(50,254)	(195,529)
	Small C&I Small	448.4	(425.8)	(190,907)	3,236.7	(96.5)	(312,238)	(503,144)
	Small C&I Large		(425.8)		0.0	(96.5)	-	-
	Public Schools		(425.8)			(96.5)		
	Oil		(425.8)			(96.5)		
	Large Power	487.0	(425.8)	(207,343)		(96.5)		(207,343)
	Irrigation		(425.8)		4,811.6	(96.5)	(464,160)	(464,160)
	Lighting		(425.8)			(96.5)		
	Wholesale	1,525.8	(425.8)	(649,671)	3,982.7	(96.5)	(384,199)	(1,033,870)
	Total System	13,417		-5,712,731	101,711		-9,811,721	(15,524,452)
			Normal	Actual	Difference			
								(11,147,824)
	Heating Degree Days		5,362.7	5,788.5	(425.8)			(4,376,628)
	Cooling Degree Days		1,395.5	1,492.0	(96.5)			(15,524,452)
	Precipitation (5 months)		16.6	21.1	(4.5)			

Exhibit__(Volker-3)

MIDWEST ENERGY, INC.
TEST YEAR ENDED AUGUST 31, 2010
WEATHER NORMALIZATION REVENUE AND ENERGY SUPPLY COST ADJUSTMENT

		Booked Test Year Volume 8/31/2010 (1)	Total Weather Normalization Volume Adj. (kWh) (2)	Average Margin Rate (3)	Weather Adjustment to Margin Revenue (4)	Incremental Purchased Power (5)	**Adjustment #8** Additional ECA Revenue (6)	**Adjustment #2** Total Weather Adj. to Revenue (7)
M System	Regular Residential	225,214,357	(5,855,034)	$0.0363	-$212,754	$0.05500	-$322,027	-$534,781
	All Electric Residential	11,511,155	(527,229)	$0.0391	-$20,593	$0.05500	-$28,998	-$49,590
	Small C&I Annual	1,335,601						
	Small C&I Small	77,356,872	(1,135,827)	$0.0405	-$45,964	$0.05500	-$62,470	-$108,434
	Small C&I Large	158,066,358	(635,912)	$0.0369	-$23,447	$0.05500	-$34,975	-$58,423
	Transmission Level	34,150,816						
	Large Power	21,089,700	(155,454)	$0.0354	-$5,507	$0.05500	-$8,550	-$14,057
	Special Contract	58,483,156	(287,333)	$0.0150	-$4,310	$0.05500	-$15,803	-$20,113
	Oil	253,707,318						
	Irrigation	49,176,233	(1,916,179)	$0.0515	-$98,693	$0.05500	-$105,390	-$204,083
	Incidental Irrigation	1,476,827						
	Lighting	6,543,264						
	Wholesale	92,790,487	(634,855)	$0.0015	-$952	$0.04000	-$25,394	-$26,346
	Total M System	990,902,144	(11,147,824)		-$412,220		-$603,608	-$1,015,827
W System	Regular Residential	66,421,743	(1,972,582)	$0.0354	-$69,766	$0.05500	-$108,492	-$178,258
	Peak Residetnial	4,331,443	(195,529)	$0.0258	-$5,040	$0.05500	-$10,754	-$15,794
	Small C&I Small	52,986,517	(503,144)	$0.0257	-$12,928	$0.05500	-$27,673	-$40,601
	Small C&I Large	37,219,560						
	Small C&I Other	29370						
	Public Schools	5,137,003						
	Oil	37,456,423						
	Large Power	82,089,220	(207,343)	$0.0292	-$6,049	$0.05500	-$11,404	-$17,452
	Irrigation	9,121,619	(464,160)	$0.0222	-$10,304	$0.05500	-$25,529	-$35,833
	Lighting	3,726,521						
	Wholesale	81,064,116	(1,033,870)	$0.0015	-$1,551	$0.04000	-$41,355	-$42,906
	Total W System	379,583,535	(4,376,628)		-$105,638		-$225,206	-$330,845
	Interdepartmetnal	102,104						
	Total System	1,370,587,783	(15,524,452)		-$517,858	$0	-$828,814	-$1,346,672

MIDWEST ENERGY, INC.
COMPARISON OF TFR REVENUES
TEST YEAR ENDED AUGUST 31, 2010

		Adjusted	12/31/2009 Current	Current	8/31/2010 Test Year	Adjusted	Change in
1	**Electric System**	kWh	TFR Rates	TFR	TFR Rates	TFR	TFR
2		Sold	$/kWh	Revenue	$/kWh	Revenue	Revenue
3	**Residential**						
4	Regular Residential - M System	230,463,038	$0.005505	$1,268,699	$0.005694	$1,312,257	$43,558
5	Total Electric - M System	12,206,180	$0.005258	$64,183	$0.005146	$62,816	-$1,367
6	Regular Residential - W System	67,615,915	$0.007551	$510,568	$0.005694	$385,005	-$125,563
7	Peak Management - W System	4,231,077	$0.007645	$32,347	$0.005528	$23,389	-$8,958
8	Total Residential	314,516,210		$1,875,796		$1,783,467	-$92,329
9							
10	**Commercial & Industrial**						
11	Annual Service - M System	1,285,249	$0.007527	$9,674	$0.005328	$6,848	-$2,826
12	General Service (Small) - M System	76,612,494	$0.005572	$426,885	$0.005328	$408,191	-$18,693
13	General Service (Medium) - M System	109,446,076	$0.004848	$530,595	$0.004727	$517,352	-$13,243
14	General Service (Large) - M System	115,154,681	$0.004848	$558,270	$0.004727	$544,336	-$13,934
15	Special Contracts (Small) - M System	0	$0.000000	$0	$0.000000	$0	$0
16	Transmission Level Service - M System	27,161,696	$0.004497	$122,146	$0.004727	$128,393	$6,247
17	Special Contracts (Large) - M System	62,301,435	$0.003790	$236,122	$0.003770	$234,876	-$1,246
18	General Service (Small) - W System	57,870,971	$0.006167	$356,890	$0.005328	$308,337	-$48,554
19	General Service (Large) - W System	197,098,636	$0.003144	$619,678	$0.004727	$931,685	$312,007
20	Public Schools - W System	4,099,389	$0.007876	$32,287	$0.005328	$21,842	-$10,445
21	Total Commercial & Industrial	651,030,627		$2,892,547		$3,101,860	$209,313
22							
23	**Oil Field**						
24	Small Oil - M System	65,140,814	$0.004231	$275,611	$0.004583	$298,540	$22,930
25	Large Oil - M System	209,788,584	$0.003878	$813,560	$0.004583	$961,461	$147,901
26	Oil - W System	41,983,688	$0.005092	$213,781	$0.004583	$192,411	-$21,370
27	Total Oil Field	316,913,086		$1,302,952		$1,452,413	$149,461
28							
29	**Irrigation**						
30	Incidental Irrigation - M System	1,171,381	$0.006815	$7,983	$0.004544	$5,323	-$2,660
31	Irrigation Frozen - M System	20,473,849	$0.005870	$120,181	$0.004544	$93,033	-$27,148
32	Irrigation TD/T&T - M System	35,830,082	$0.005870	$210,323	$0.004544	$162,812	-$47,511
33	Irrigation - W System	11,002,874	$0.010172	$111,921	$0.004544	$49,997	-$61,924
34	Total Irrigation	68,478,186		$450,408		$311,165	-$139,243
35							
36	**Lighting**						
37	M System	7,140,073	$0.002351	$16,786	$0.003034	$21,663	$4,877
38	W System	3,746,232	$0.003446	$12,910	$0.003034	$11,366	-$1,543
39	Total Lighting	10,886,305		$29,696		$33,029	$3,333
40							
41	**Wholesale**						
42	M System	0	$0.000000	$0		$0	$0
43	W System	0	$0.000000	$0		$0	$0
44	Total Wholesale	0		$0		$0	$0
45							
46	**Interdepartmental**	0	$0.000000	$0		$0	$0
47							
48	**Totals**	**1,361,824,414**		**$6,551,399**		**$6,681,933**	**$130,534**
49							

Midwest Energy, Inc.
Transmission Formula Rate
Attachment H-1 to Open Access Transmission Tariff - Formula Rate
Test Year Ended 8-31-2010

	Formula Rate	Notes	FERC Form 1 Page # or Instruction	Year Ending 8/31/10
	Shaded cells are input cells			
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense		p354.21.b	550,559
2	Total Wages Expense		p354.28b	7,447,686
3	Less A&G Wages Expense		p354.27b	2,019,555
4	Total		(Lines 2 - 3)	5,428,131
5	**Wages & Salary Allocator**		(Lines 1 / 4)	**10.1427%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	Sheet 7	418,036,594
7	Common Plant In Service - Electric		(Line 24)	17,576,208
8	Total Plant In Service		(Sum Lines 6 to 7)	435,612,802
9	Accumulated Depreciation (Total Electric Plant)		p219.29c	152,885,756
10	Accumulated Intangible Amortization	(Note A)	p200.21c	0
11	Accumulated Common Amortization - Electric	(Note A)	p356	0
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356.1	7,049,041
13	Total Accumulated Depreciation		(Sum Lines 9 to 12)	159,934,797
14	Net Plant		(Lines 8 - 13)	275,678,005
15	Transmission Gross Plant		(Lines 29 - Line 28)	92,509,088
16	**Gross Plant Allocator**		(Lines 15 / 8)	**21.2365%**
17	Transmission Net Plant		(Lines 39 - Line 28)	55,114,530
18	**Net Plant Allocator**		(Lines 17 / 14)	**19.9924%**
	Plant Calculations			
	Plant In Service			
19	Transmission Plant In Service	(Note B)	p207.58.g	88,818,228
20	This line is not used, but is held for future use.			0
21	This line is not used, but is held for future use.			0
22	**Total Transmission Plant In Service**		(Lines 19 - 20 + 21)	**88,818,228**
23	General & Intangible		p205.5.g & p207.99.g	18,813,122
24	Common Plant (Electric Only)	(Notes A & B)	p356	17,576,208
25	Total General & Common		(Lines 23 + 24)	36,389,330
26	Wage & Salary Allocation Factor		(Line 5)	10.14270%
27	**General & Common Plant Allocated to Transmission**		(Lines 25 * 26)	**3,690,860**
28	**Plant Held for Future Use (Including Land)**	(Note C)	p214	0
29	**TOTAL Plant In Service**		**(Lines 22 + 27 + 28)**	**92,509,088**

Midwest Energy, Inc.
Transmission Formula Rate
Attachment H-1 to Open Access Transmission Tariff - Formula Rate
Test Year Ended 8-31-2010

Formula Rate		Notes	FERC Form 1 Page # or Instruction	Year Ending 8/31/10
Shaded cells are input cells				
	Accumulated Depreciation			
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	35,790,183
31	Accumulated General Depreciation		p219.28.c	8,768,988
32	Accumulated Intangible Amortization		(Line 10)	0
33	Accumulated Common Amortization - Electric		(Line 11)	0
34	Common Plant Accumulated Depreciation (Electric Only)		(Line 12)	7,049,041
35	Total Accumulated Depreciation		(Sum Lines 31 to 34)	15,818,029
36	Wage & Salary Allocation Factor		(Line 5)	10.14270%
37	**General & Common Allocated to Transmission**		(Lines 35 x 36)	**1,604,375**
38	**TOTAL Accumulated Depreciation**		**(Lines 30 + 37)**	**37,394,558**
39	**TOTAL Net Property, Plant & Equipment**		**(Lines 29 - 38)**	**55,114,530**
Adjustment To Rate Base				
	Prepayments			
40	Prepayments (Account 165)	(Note A)	p111.57c	393,956
41	Net Plant Allocation Factor		(Line 18)	19.9924%
42	**Total Prepayments Allocated to Transmission**		(Lines 40 x 41)	**78,761**
	Materials and Supplies			
43	Materials and Supplies	(Note A)	Sheet 7	6,392,005
44	Wage & Salary Allocation Factor		(Line 5)	10.14%
45	Total Transmission Allocated		(Linex 43 x 44)	648,322
46	Transmission Materials & Supplies - if not included in line 43			0
47	**Total Materials & Supplies Allocated to Transmission**		(Lines 45 + 46)	**648,322**
	Cash Working Capital			
48	Operation & Maintenance Expense		(Line 72)	2,324,049
49	1/8th Rule		x 1/8	12.5%
50	**Total Cash Working Capital Allocated to Transmission**		(Lines 48 x 49)	**290,506**
	Construction Work in Progress (CWIP)			
51	Construction Work in Progress		Sheet 8	17,596,077
52	Gross Plant Allocation Factor		(Line 16)	21.2365%
53	**Total Construction Work in Progress**		(Lines 51 x 52)	**3,736,798**
54	**TOTAL Adjustment to Rate Base**		(Line 42+47+50+53)	**4,754,387**
55	**Rate Base**		(Lines 39 + 54)	**59,868,917**

Midwest Energy, Inc.
Transmission Formula Rate
Attachment H-1 to Open Access Transmission Tariff - Formula Rate
Test Year Ended 8-31-2010

	Formula Rate	Notes	FERC Form 1 Page # or Instruction	Year Ending 8/31/10
	Shaded cells are input cells			
	O&M			
	Transmission O&M			
56	Transmission O&M		p321.112.b	1,815,648
57	Less Account 565	(Note I)	p321.96.b	-
58	Less Schedule 12 payments if specifically recovered elsewhere	(Note I)	MWE Data	-
59	Less Transmission Share of Acc. 454 - Rent from Elec Property	(Note I)	Sheet 9	45,034
60	Plus Transmission Lease Payments	(Note I)		0
61	**Transmission O&M**		(Lines 56-57+58+60)	1,770,614
	Allocated General & Common Expenses			
62	Common Plant O&M	(Note A)	p356	0
63	Total A&G		p323.197.b	5,158,509
64	Less Property Insurance Account 924		p323.185.b	306,844
65	Less EPRI Dues	(Note D)	p352-353	0
66	**General & Common Expenses**		(Lns 62+63)- (Lns 64+65)	4,851,665
67	Wage & Salary Allocation Factor		(Line 5)	10.1427%
68	**General & Common Expenses Allocated to Transmission**		(Lines 66 x 67)	**492,090**
	Directly Assigned A&G			
69	Property Insurance Account 924		(Line 64)	306,844
70	Net Plant Allocation Factor		(Line 18)	19.99%
71	**A&G Directly Assigned to Transmission**		(Lines 69 x 70)	**61,345**
72	**Total Transmission O&M**		**(Lined 61 + 68 + 71)**	**2,324,049**
	Depreciation & Amortization Expense			
	Depreciation Expense			
73	Transmission Depreciation Expense		p336.7b&c	1,411,295
74	General Depreciation		p336.10.b	221,132
75	Intangible Amortization	(Note A)	p336.1d&e	45,068
76	Total		(Lines 74 + 75)	266,200
77	Wage & Salary Allocation Factor		(Line 5)	10.1427%
78	**General Depreciation Allocated to Transmission**		(Lines 76 x 77)	**27,000**
79	Common Depreciation - Electric Only	(Note A)	p336.11.b	1,599,463
80	Common Amortization - Electric Only	(Note A)	p356 or p336.11.d	0
81	Total		(Lines 79 + 80)	1,599,463
82	Wage & Salary Allocation Factor		(Line 5)	10.1427%
83	**Common Depreciation - Electric Only Allocated to Transmission**		(Lines 81 x 82)	**162,229**
84	**Total Transmission Depreciation & Amortization**		**(Lines 73 + 78 + 83)**	**1,600,524**
	Taxes Other than Income			
85	**Taxes Other than Income**		Sheet 6	**993,538**
86	**Total Taxes Other than Income**		**(Line 85)**	**993,538**

Midwest Energy, Inc.
Transmission Formula Rate
Attachment H-1 to Open Access Transmission Tariff - Formula Rate
Test Year Ended 8-31-2010

Formula Rate			Notes	FERC Form 1 Page # or Instruction	Year Ending 8/31/10
Shaded cells are input cells					
Return / Capitalization Calculations					
	Long Term Interest				
87	Long Term Interest (Consolidated)			p117.62c through 67c	12,457,839
88	Allocated to Electric Division			Sheet 7	87.6178%
89	**Long Term Interest (Electric only)**			(Lines 87 x 88)	10,915,289
	Patronage Capital & Other Equity				
90	Patronage Capital & Other Equity (Consolidated)			p112.16c	128,765,863
91	Less Account 216.1 - Unamortized Undistributed Subsidiary Earnings			p112.12c	0
92	**Remaining Patronage Capital & Other Equity**			(Lines 90 - 91)	128,765,863
93	Allocated to Electric Division			Sheet 7	87.6178%
94	**Patronage Capital & Other Equity (Electric only)**			(Lines 92 x 93)	112,821,867
	Capitalization				
95	Long Term Debt (Consolidated)			p112.18.c through 21.c	241,424,790
96	Allocated to Electric Division			Sheet 7	87.6178%
97	Total Long Term Debt (Electric only)			(Line 95 x 96)	211,531,185
98	Patronage Cap. Alloc. to Elec Division			(Line 94)	112,821,867
99	**Total Capitalization (Electric only)**			(Lines 97 + 98)	324,353,052
100	Debt %	Total Long Term Debt		(Lines 97 / 99)	65.2163%
101	Capital %	Patronage Cap. Alloc. to Elec Division		(Lines 98 / 99)	34.7837%
102	Debt Cost	Total Long Term Debt		(Lines 89 / 97)	5.1601%
103	Equity Cost	Patronage Cap. Alloc. to Elec Division	(Note F)	Fixed	10.1491%
104	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Lines 100 x 102)	3.3652%
105	Weighted Cost of Capital	Patronage Cap. Alloc. to Elec Division		(Lines 101 x 103)	3.5302%
106	**Total Return (R)**			(Lines 104 + 105)	**6.8955%**
107	**Investment Return = Rate Base * Rate of Return**			**(Lines 55 x 106)**	**4,128,248**
REVENUE REQUIREMENT					
	Summary				
108	Net Property, Plant & Equipment			(Line 39)	55,114,530
109	Adjustment to Rate Base			(Line 54)	4,754,387
110	**Rate Base**			(Line 55)	**59,868,917**
111	O&M			(Line 72)	2,324,049
112	Depreciation & Amortization			(Line 84)	1,600,524
113	Taxes Other than Income			(Line 86)	993,538
114	Investment Return			(Line 107)	4,128,248
115	**Gross Revenue Requirement**			**(Sum Lines 111 to 114)**	**9,046,359**

Midwest Energy, Inc.
Transmission Formula Rate
Attachment H-1 to Open Access Transmission Tariff - Formula Rate
Test Year Ended 8-31-2010

Formula Rate		Notes	FERC Form 1 Page # or Instruction	Year Ending 8/31/10

Shaded cells are input cells

	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
116	Transmission Plant In Service		(Line 19)	88,818,228
117	Excluded Transmission Facilities	(Note H)	Sheet 8	3,093,987
118	Included Transmission Facilities		(Lines 116 - 117)	85,724,241
119	Inclusion Ratio		(Lines 118 / 116)	96.5165%
120	Gross Revenue Requirement		(Lines 115)	9,046,359
121	**Adjusted Gross Revenue Requirement**		(Lines 119 x 120)	8,731,228
122	Less Account 456 - Operating Revenue from Non-Firm Transmission Service		Sheet 3	332,489
123	**Net Revenue Requirement**		**(Line 121)**	**8,398,739**
	Net Plant Carrying Charge without New Investment Incentive			
124	Net Revenue Requirement		(Line 123)	**8,398,739**
125	Net Transmission Plant		(Lines 19 - 30)	**53,028,045**
126	Net Plant Carrying Charge		(Lines 124 / 125)	**15.8383%**
127	Net Plant Carrying Charge without Depreciation		((Ln124 - 73) / Ln125)	**13.1769%**
128	**Net Revenue Requirement**		(Line 123)	**8,398,739**
129	This line is not used, but is held for future use.			
130	**Net Zonal Revenue Requirement**		(Line 128)	**8,398,739**
	Network Zonal Service Rate			
131	12 CP Peak	(Note G)	Sheet 11	**239,539**
132	Rate ($/KW-Year)		(Lines 130 / 131)	**35.0621**

	Firm Transmission Service Rates		**Non-Firm Transmission Service Rates**	
133	Annual Point-to-Point Firm ($/kW)	35.0621	Annual Point-to-Point Non-Firm ($/kW)	n/a
134	Monthly Firm ($/kW) - (Annual/12)	2.9218	Monthly Non-Firm ($/kW) - (Annual/12)	2.9218
135	Weekly Firm ($/kW) - (Annual/52)	0.6743	Weekly Non-Firm ($/kW) - (Annual/52)	0.6743
136	Daily Firm ($/kW) - (Weekly/5)	0.1349	Daily Non-Firm ($/kW) - (Weekly/5)	0.1349
137	Hourly Firm ($/MWh)	n/a	Hourly Non-Firm ($/MWh) (Daily/16 x 1000)	8.43

Notes

A Electric portion only
B Exclude Construction Work In Progress.
C Transmission Portion Only
D All EPRI Annual Membership Dues
E Transmission lines leased from others. Midwest does not lease transmission lines from other entities.
F Equity cost shall remain fixed as approved by the Kansas Corporation Commission, and shall not change until a change in the cost of equity as approved by the Commission becomes effective.
G Average aggregated firm demand during each of the 12 calendar-month peak demand hours (i.e., "12 CP") for Network and Point to Point transactions of over one year on the Company's transmission system.
H Amount of transmission plant excluded from rates, includes investment that does not pass the FERC tests for functionalization as transmission plant. Midwest Energy details specific segments of line in Attachment 3.
I Midwest Energy Records assessments by SPP less revenues from SPP in account 555 (i.e. debit and credits) . The amounts offset each other completely. However, SPP also adds its administrative fees thereby making a net expense charged to 555. This administrative fee is recovered through the ECA mechanism and therefore should not be included as part of the TFR. MWE does not record anything in account 565. ="Account 566 is the account where NERC and FERC assessments are charged and are included in Transmission O&M expense (line 56)."

END

Midwest Energy, Inc.
Transmission Formula Rate
Attachment H-1 to Open Access Transmission Tariff - Rate Class Allocations
Test Year Ended 8-31-2010

Month Year	System Firm Peak Load	Retail Contribution to Peak	M System Regular Residential	M System All Elec Residential	M System Annual Service	M System General Svc Small	M System General Svc Small - DR	M System General Svc Medium	M System General Svc Large	M System General Svc Large-TD	M System General Svc Large-Heat
12CP Trans. Allocator	270,529	215,250									
Percent of Total	100.00%	79.57%									
12CP Prod Allocator		215,433	42,366	2,033	226	12,882	204	16,601	15,621	589	1,248
Percent of Total		68.88%	19.67%	0.94%	0.10%	5.98%	0.09%	7.71%	7.25%	0.27%	0.58%
Revenue Requirement	$8,398,739	$6,682,566	$1,312,257	$62,816	$6,848	$401,800	$6,391	$517,352	$496,356	$9,102	$38,879
Billing Determinants		1,361,824,414	230,463,038	12,206,180	1,285,249	75,412,930	1,199,564	109,446,076	105,004,352	1,925,555	8,224,774
TFR Retail Rate			$0.005694	$0.005146	$0.005328	$0.005328	$0.005328	$0.004727	$0.004727	$0.004727	$0.004727

	System Firm Peak Load	Retail Contribution to Peak	M System Oil Field Svc Small	M System Oil Field Svc Small - DR	M System Oil Field Svc Large	M System Irrigation Frozen	M System Irrigation T&T/TOD	M System Irrigation Incidental	M System Lighting	M System Special Contract	M System Transmission Level Svc
12CP Trans. Allocator	270,529	215,250									
Percent of Total	100.00%	79.57%									
12CP Prod Allocator		215,433	3,550	6,063	31,006	4,576	2,852	213	465	7,920	4,164
Percent of Total		68.88%	1.65%	2.81%	14.39%	2.12%	1.32%	0.10%	0.22%	3.68%	1.93%
Revenue Requirement			$176,485	$122,055	$961,461	$93,033	$162,812	$5,323	$21,663	$234,886	$128,393
Billing Determinants			38,508,590	26,632,224	209,788,584	20,473,849	35,830,082	1,171,381	7,140,073	62,301,435	27,161,696
TFR Retail Rate			$0.004583	$0.004583	$0.004583	$0.004544	$0.004544	$0.004544	$0.003034	$0.003770	$0.004727

	System Firm Peak Load	Retail Contribution to Peak	W System Regular Residential	W System Peak Residential	W System General Svc Small	W System Schools	W System Large Power	W System Oil Field Service	W System Irrigation Service	W System Lighting
12CP Trans. Allocator	270,529	215,250								
Percent of Total	100.00%	79.57%								
12CP Prod Allocator		215,433	12,355	764	9,991	723	30,182	6,205	2,390	244
Percent of Total			5.73%	0.35%	4.64%	0.34%	14.01%	2.88%	1.11%	0.11%
Revenue Requirement			$385,005	$23,389	$308,337	$21,842	$931,685	$192,411	$49,997	$11,366
Billing Determinants			67,615,915	4,231,077	57,870,971	4,099,389	197,098,636	41,983,688	11,002,874	3,746,232
TFR Retail Rate			$0.005694	$0.005528	$0.005328	$0.005328	$0.004727	$0.004583	$0.004544	$0.003034

Exhibit__(Volker-5)

MIDWEST ENERGY, INC.
TEST YEAR ENDED AUGUST 31, 2010
DETERMINATION OF RESIDENTIAL BLOCK VALUES

Rate Class	(1) Constant (kWh/Cust/Mo)	(2) Summer Cooling Degree Days*	(3) Sensitivity per CCD per Customer	(4) Average Summer Air Conditioning (kWh)	(5) Average Cooling Per Customer Per Summer Month
M Residential	492.45	1,146	1.63	1,868.31	623
M All Electric	584.44	1,146	1.3	1,490.06	497
W Residential	533.67	1,146	1.76	2,017.31	672

* Normal 30 year average cooling degree days for months of July, August, and September.

Exhibit__(Volker-6)

MIDWEST ENERGY, INC.
TEST YEAR ENDED AUGUST 31, 2010
CUSTOMER IMPACT OF CHANGING RATE BLOCK DESIGN

Line	Rate Class	(1) Number of Customers in Sample	(2) Current Rate Design Calculated Revenue	(3) Inclining Block Design Revenue	(4) Percent Difference	(5) Customer's Bills Lowered 5% or More	(6) Customer's Bills Increased 5% or More	(7) Percent with Bills Increased 5% or More
1	M Regular Residential	1,438	$1,441,793.28	$1,444,711.21	-0.2%	139	70	4.9%
2	M All-Electric Residential	596	$749,701.40	$749,701.01	0.0%	9	18	3.0%
3	W Regular Residential	605	$533,691.64	$533,688.85	0.0%	0	5	0.8%
4	Total Residential	2,639	$2,725,186.32	$2,728,101.07	-0.1%	148	93	3.5%
5								
6	M General Service Small	654	$746,726.39	$746,725.80	0.0%	354	40	6.1%