Exhibit No.:	
Issue:	Minimum Filing Requirements, Revenues, Depreciation Study, Fuel Adjustment Clause, Electric Class Cost of Service Study, Rate Design, Rules and Regulations, Transmission Tracker, Renewable Energy Standard and Missouri Energy Efficiency Investment Act of 2009
Witness:	Tim M. Rush
Type of Exhibit:	Direct Testimony
Sponsoring Party:	KCP&L Greater Missouri Operations Company
Case No.:	ER-2010-____
Date Testimony Prepared:	June 4, 2010

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2010-____

DIRECT TESTIMONY

OF

TIM M. RUSH

ON BEHALF OF

KCP&L GREATER MISSOURI OPERATIONS COMPANY

Kansas City, Missouri
June 2010

"[redacted]**" Designates "Highly Confidential" Information Has Been Removed Pursuant To 4 CSR 240-2.135**

DIRECT TESTIMONY

OF

TIM M. RUSH

Case No. ER-2010-____

Q: Please state your name and business address.

A: My name is Tim M. Rush. My business address is 1200 Main Street, Kansas City, Missouri 64105.

Q: By whom and in what capacity are you employed?

A: I am employed by Kansas City Power & Light Company ("KCP&L") as Director, Regulatory Affairs.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of KCP&L Greater Missouri Operations Company ("GMO" or the "Company") for the territories served by L&P ("L&P") and MPS ("MPS").

Q: What are your responsibilities?

A: My general responsibilities include overseeing the preparation of the rate case, class cost of service ("CCOS") and rate design of both KCP&L and GMO. I am also responsible for overseeing the regulatory reporting and general activities as they relate to the Missouri Public Service Commission ("MPSC" or "Commission").

Q: Please describe your education, experience and employment history.

A: I received a Master of Business Administration degree from Northwest Missouri State University in Maryville, Missouri. I did my undergraduate study at both the University of Kansas in Lawrence and the University of Missouri in Columbia. I received a

Bachelor of Science degree in Business Administration with a concentration in Accounting from the University of Missouri in Columbia.

Q: Please provide your work experience.

A: I was hired by KCP&L in 2001 as the Director, Regulatory Affairs. Prior to my employment with KCP&L, I was employed by St. Joseph Light & Power Company ("Light & Power") for over 24 years. At Light & Power, I was Manager of Customer Operations from 1996 to 2001, where I had responsibility for the regulatory area, as well as marketing, energy consultant and customer services area. Customer services included the call center and collections areas. Prior to that, I held various positions in the Rates and Market Research Department from 1977 until 1996. I was the manager of that department for fifteen years.

Q: Have you previously testified in a proceeding before the MPSC or before any other utility regulatory agency?

A: I have testified on several occasions before the MPSC on a variety of issues affecting regulated public utilities. I have additionally testified at the Federal Energy Regulatory Commission and the Kansas Corporation Commission.

Q: What is the purpose of your testimony?

A: The purposes of my testimony are to:

I.) Explain how the Company satisfied the MPSC's minimum filing requirements ("MFR") under 4 CSR 240-3.030;

II.) Explain how the Company satisfied the depreciation study requirements under 4 CSR 240-3.160;

III.) Discuss the Fuel Adjustment Clause ("FAC") filing requirements;

IV.) Provide the retail revenue adjustment to reflect the annualized and normalized revenue level for both MPS and L&P;

V.) Discuss rate design and propose modifications to the FAC for MPS and L&P;

VI.) Discuss the results of GMO's CCOS studies for both MPS and L&P;

VII.) Recommend changes to the Company's Rules and Regulations;

VIII.) Discuss a transmission tracker as an alternative to inclusion of the transmission costs in the FAC;

IX.) Discuss the Renewable Energy Standard ("RES") rulemaking; and

X.) Discuss the Missouri Energy Efficiency Investment Act of 2009 ("MEEI") rulemaking.

I. MINIMUM FILING REQUIREMENTS

Q: What is the purpose of this part of your testimony?

A: The purpose of this part of my testimony is to confirm that GMO has satisfied the MPSC's MFR, as set forth in 4-CSR 240-3.030.

Q: How did GMO satisfy the MFR?

A: The following information was prepared to address the specific requirements of the MFR as outlined in 4-CSR 240-3.030(3):

A: Letter of transmittal;

B: General information, including:

1. Amount of dollars of the aggregate annual increase and percentage over current revenues;
2. Names of counties and communities affected;
3. Number of customers to be affected;

4. Average change requested in dollars and percentage change from current rates;
5. Proposed annual aggregate change by general categories of service and by rate classification;
6. Press releases relative to the filing; and
7. Summary of reasons for the proposed changes.

Q: Are you sponsoring this information?

A: Yes, I am.

Q: Was this information prepared under your direct supervision?

A: Yes, it was.

II. DEPRECIATION STUDY REQUIREMENTS

Q: Were the provisions of 4 CSR 240-3.160 addressed concerning a depreciation study, database and property unit in this filing?

A: Yes, the Company performed a depreciation study for this case. Company witness John J. Spanos provides the depreciation study and summarizes the results of the study in his Direct Testimony. Additionally, Company witness John P. Weisensee addresses the depreciation rates used in the determination of the revenue request in this filing in his Direct Testimony.

III. FUEL ADJUSTMENT CLAUSE FILING REQUIREMENTS

Q: Does the Company currently have an approved FAC?

A: Yes. The FAC was initially approved in Case No. ER-2007-0004 on May 17, 2007 (effective May 27, 2007). Several modifications and clarifications were made to the FAC in the most recent rate case, Case No. ER-2009-0090, which became effective on

September 1, 2009. The first accumulation period for the FAC was June – November 2007. Recovery of the deficiency occurred over the period March 2008 – February 2009. The second accumulation period was December 2007 – May 2008. Recovery of the deficiency for the second accumulation period occurred over the period September 2008 – August 2009. The third accumulation period was June – November 2008. Recovery of the deficiency for the third accumulation period occurred over the period March 2009 – February 2010. The fourth accumulation period was December 2008 – May 2009. Recovery of the deficiency for the fourth accumulation period began September 2009 and will conclude August 2010. The fifth accumulation period was June – November 2009. Recovery for the deficiency for the fifth accumulation period began March 2010 and will conclude February 2011. The Company is currently in the sixth accumulation period of December 2009 – May 2010.

Q: What are the rules for continuing an FAC?

A: The requirements for continuing an FAC are found in Section 386.266 RSMo and Commission Rules 4 CSR 240-20.090 and 4 CSR 240-3.161(3)(A) through (T). This supporting information is summarized in the attached schedules TMR2010-1 FAC 4CSR240, TMR2010-2 Important Notice and TMR2010-3 Proposed FAC Rate Schedules.

Q: Did the Company meet all of the filing requirements to continue the FAC including the line loss study required in 4 CSR 240-20.090?

A: Yes, the Company has met all of the filing requirements to continue the FAC including the completion of a line loss study.

Q: Is the Company requesting to continue the FAC?

A: Yes. The FAC is made up of fuel and purchased power expense plus proposed addition of increasing transmission costs, less off-system sales revenues and was approximately 52% of total operation and maintenance expense in the test year ending December 31, 2009. The FAC in the first five accumulation periods has been approximately 22% higher than the calculated base amounts. The increasing prices for natural gas, coal, coal transportation and transmission costs are not costs that can be controlled by the Company, nor are they costs that can be absorbed by reducing other costs.

Q: Is the Company proposing to change the base amounts included in the tariff?

A: The Company is not proposing to re-base the FAC. The current base amounts are $0.02348 per kWh net system input for MPS and $0.01642 per kWh net system input for L&P. The proposed base amounts are $0.02626 per kWh net system input for MPS and $0.01715 per kWh net system input for L&P. The changes proposed are due to adjustments made to the current base amounts to include new costs which are being proposed as additions to the FAC within this case.

IV. ANNUALIZED/NORMALIZED REVENUES

Q: Were the retail revenues included in this filing prepared by you or under your supervision?

A: Yes, they were.

Q: Will you describe the method used in developing the revenues for this case?

A: Both the weather-normalized kWh sales and customer levels by rate class were developed by Company witness George M. McCollister. Mr. McCollister explains those figures in his Direct Testimony. Monthly bill frequencies for the test year ending December 31, 2009, that contain the billing units for each of the billing blocks for the various rate components were developed under my supervision. For example, the MPS residential general use rate has two billing blocks in the winter period and three billing blocks in the summer period and the L&P residential general use rate has two billing blocks in the winter period, while only one billing block in the summer period. The bill frequencies collect the actual usage that is billed in each of the billing blocks for each month of the test period. It also collects the actual number of customers in each of the months. By applying the actual rates to the usage in each of the billing blocks, the actual revenues can be reproduced. This method provided the basis for determining the overall revenues to be used in this case. The Company determined monthly revenues by applying the normalized sales and customer levels for each month represented in the test period to the corresponding bill frequency. The resulting normalized sales and customer levels from this were then multiplied by the rates that took effect on September 1, 2009. The sum of these revenues was compared to the actual test year ending December 31, 2009 revenues to determine the revenue adjustment contained in the Summary of Adjustments attached to the Direct Testimony of Company witness John P. Weisensee as Schedule JPW2010-2 (adjustment R-20).

V. ELECTRIC RATE DESIGN

Q: Are you sponsoring the electric tariffs filed in this case?

A: Yes, I am.

Q: Are you recommending changes to the rate design based on the CCOS study filed in this case?

A: Not at this time.

Q: Please describe the proposed rate design recommendation for the electric tariffs and any additional proposed changes to the tariffs?

A: The Company is requesting an increase in rates of $97.9 million. The Company is proposing that this non-fuel requested increase be spread to all customer classes and all non-fuel rate components on an equal percentage basis. The proposed non-fuel increase in rates at MPS is $75.8 million or 14.43% and the proposed non-fuel increase in rates at L&P is $22.1 million or 13.87% as measured against total jurisdictional revenue. The Company is proposing to modify the FAC by including transmission costs in the FAC.

Q: Is there an alternative to addressing the transmission costs within the FAC?

A: An alternative means to addressing the transmission costs as proposed in this filing and included in the FAC mechanism outlined on Schedule TMR2010-1 FAC 4 CSR 240, whereby transmission costs are included in the FAC, would be through a transmission tracking mechanism. For a complete discussion of this alternative, see section VIII of this direct testimony.

Q: Among the proposed changes to the rate tariffs, are there any changes sought which correct a previous error?

A: Yes, there is. Inadvertently, in the production of final tariffs in Case No. ER-2009-0090 the Company submitted an L&P Revised Sheet 48 for Private Area Lighting containing a price in error. The error appears as $0.0767, the charge for "Additional UG Secondary (per section, per month)" and section length of 50'. It should have been $0.92. By design this is a monthly charge. The figure $0.92 is the result of dividing $11.04 by twelve (12) months, however, the error occurred in further dividing $0.92 by twelve (12) once again. After discovering the error, the Company discussed the matter with MPSC Staff and came to an agreement to correct it in this rate case. Including the proposed non-fuel increase in rates the new rate for will be $1.06.

.Q: **Do you propose a non-rate related change to L&P Private Area Lighting?**

A: Yes. I propose changes to Tariff Sheets 47 and 48 to limit the availability of some services to units in service as of May 4, 2011. With regard to Revised Sheet 47, we wish to limit Private Area Mercury Vapor fixtures, Directional Flood Mercury Vapor fixtures, Special Metal Halide fixtures, and Special High Mast High Pressure Sodium fixtures.

Q: **Why do you wish to limit future availability of these items?**

A: Mercury Vapor technology and Metal Halide products are less energy efficient than alternatives. Since energy efficiency is driving customer decisions, interest in this technology is waning. In addition, as a result of the *Energy Policy Act of 2005*, 42 U.S.C. 15801 *et seq.*, manufacturers no longer sell new Mercury Vapor ballasts, a critical part to the lamp. Also, High Mast, High Pressure Sodium fixtures are principally used in highway applications and rarely requested, requiring long lead times, a greater level of design work, specialized training, and specialized equipment to service these fixtures.

Q: **What change are you proposing to Revised Sheet 48?**

A: We seek to limit the availability of certain metal poles for overhead construction as of May 4, 2011. This change is sought because, by design, metal poles are strictly intended for underground service applications. Also, there are some types of poles that are not regularly requested by customers, requiring long lead times, and a greater level of design work.

Q: What specific poles listed on Revised Sheet 48 are affected by the proposed changes?

A: The Company would like to delete references to overhead service ("OH") under the Metal Pole Rates section. Also, we would like to limit the availability of the following poles to those in service as of May 4, 2011. They are: Metal Poles, Bronze, Round/Square, 39'; Steel pole, 60'; Special Luminaires, Decorative Lantern HPS, 150W; Signliter, Boxliter HPS, 400 W.

Q: Do you propose any non-rate related changes to MPS Private Area Lighting and Municipal Street Lighting?

A: Yes, I propose changes to MPS Municipal Street Lighting tariffs found on Sheet 89 and MPS Private Area Lighting tariffs found on Sheet 92.

Q: What changes are you proposing to Sheet 89 and Sheet 92?

A: Change Sheet 89 to limit the availability of the following units to those in service as of May 4, 2011. The styles include Special Luminaire: Lantern HPS, 5 Globe HPS, and Single Globe HPS. This change allows the company to respond to MPS customers' most requested lamp head styles—Cobra-head style lights for street lighting applications and open-bottom style lights for area lighting applications. This change also allows greater standardization throughout the GMO service territory.

Furthermore, on Sheet 92, the Company seeks to limit the availability of Metal Halide products to those in service as of May 4, 2011. . As previously noted, Metal Halide products are less energy efficient than other alternatives. As noted above, since energy efficiency is driving customer decisions; interest in this technology is decreasing.

Q: **Do your proposed tariffs for lighting involve any other non-rate related changes?**

A: Yes. I propose changes to MPS Sheet 95, Non-Standard Street And Area Light Facilities Electric–limiting the Availability and Company Owned sections of this tariff to units in service on May 4, 2011. This limitation decreases complexity caused by the number of combinations and permutations of available lighting devices. It is our belief that decreasing complexity and increasing standardization improves service to the communities we serve. The Company also continues to investigate alternatives to decorative non-standard lighting.

The Availability section on Sheet 95 provides the scope to the Company Owned Facilities and the Customer Owned Facilities sections. In light of the proposed limitation affecting the change to the Company Owned Facilities section and to clarify the availability of the Customer Owned Facilities section, we propose addition of the following language:

"AVAILABILITY. This schedule is available to all customers, otherwise qualified to receive service under the Municipal Street Lighting Service or the Private Area Lighting Service, that desire to purchase, own, install and maintain non-standard lighting facilities for which Company provides unmetered energy service."

Q: **Do you have any other changes to the tariffs?**

A: Yes. I propose to add language to Sheet 74 in order to clarify the secondary voltage level rate for the transmission congestion charge. This change will clarify the rate on the tariff, alleviate customer confusion and improve the administration of this program.

VI. ELECTRIC CLASS COST OF SERVICE

Q: Has the Company performed an electric CCOS study for this case?

A: Yes, the Company performed a CCOS study for this case. Company witness Paul Normand provides the CCOS study and summarizes the results of the study in his Direct Testimony.

Q: What methodology did Mr. Normand use in preparing his CCOS study?

A: He used a methodology often referred to as the Base, Intermediate, Peak ("BIP") method. Essentially, this methodology allocates costs to classes based on the utilization of production facilities. This is described in detail in Mr. Normand's Direct Testimony.

Q: Can you generally describe the outcome of the CCOS?

A: In the MPS rate jurisdiction, the CCOS results indicate that the Residential class is slightly above system average ROR while the comparable Small General Service is somewhat higher than the overall system average ROR except for the Primary subclass which is below. The remaining two major classes of Large General Service and Large Power Service are, however, somewhat below the overall Company system average ROR.

In the L&P rate jurisdiction the CCOS results indicate that the Residential class is slightly above system average ROR while the comparable Small General Service is well above the overall system average ROR except the Separately Metered which is well below average ROR. The Large General Service classes are also well above the system average ROR. In the Large Power Service class, both Transmission and Substation service classes yield ROR at the system average with the remaining Primary and Secondary Service classes producing ROR well below the system average ROR.

VII. RULES AND REGULATIONS

Q: What changes is the Company seeking to its Rules and Regulations?

A: There are three general areas of proposed changes offered regarding the Rules and Regulations. The first seeks to clarify and better define language regarding the protection of Company property. The second change is a request to amend reconnection fees. The third seeks a variance regarding the order of priority for partial payments made to a customers' accounts.

Q: What clarity to the property protection section are you seeking to achieve?

A: Customers and the Company are better served when the language of the Rules and Regulations is simple, unambiguous, and clearly stated since the Rules and Regulations lay the foundation to policies and interactions with customers. The Company identified an opportunity for additional clarity to the language regarding protection of the Company's property—addressing a potential point of confusion and adding definitions to key terms.

The Company seeks to add the term 'unauthorized' to Protection of Company's Property Section 4.02 and offer definitions for the terms 'unauthorized' and 'tampering' in the definitions section.

Q: How will Protection of Company's Property Section 4.02 read with the addition of 'unauthorized'?

A: The proposed change to Rule 4.02(B), Sheet R-27 will read as follows:

> Company may discontinue service to a customer and remove its equipment from the customer's premises without notice as stated in Section 2.05 in these Rules if evidence is found that its service wires, meters, or other appurtenances on the

premises have been tampered with in such manner that the customer is then receiving or may have received unmetered service or *unauthorized use*. In such event, Company may require the customer to pay for such electric energy as Company may estimate from available information to have been used but not registered by Company's meter and to increase his/her deposit or require a surety bond (in an amount determined by Company) before electric service is restored; and, in addition thereto, the customer shall be required to bear all associated costs incurred by Company, including, but not limited to, estimated labor charges, investigation and prosecution costs, material charges, and such protective equipment as, in its judgment, may be necessary.

Q: What definition of 'unauthorized use' is the Company proposing to add?

We are requesting the addition of the following definition for 'Unauthorized Use' within the definitions Section 1, beginning on Sheet R-5A:

Proposed Item AB on Sheet R-5A defines Unauthorized Use is to use or receive the direct benefit of all, or a portion of, the utility service with knowledge of, or reason to believe that diversion, tampering or other unauthorized connection existed at the time of the use, or that the use or receipt was fraudulent and/or without the authorization or consent of the utility. Includes but is not limited to: (a) tampering with or reconnection of service wires and/or electric meters to obtain metered use of electricity, (b) the unmetered use of electricity resulting from unauthorized connections, alterations or modifications to service wires and or electric meters, (c) placing conductive material in the meter socket to allow unmetered electricity to flow from the line-side to load-side of the service, (d) installing an unauthorized electric meter in place of the meter assigned to the account, (e) inverting or repositioning the meter to alter registration, (f) disrupting the magnetic field or wireless communication of the meter causing altered registration, (g) damaging or altering the electric meter to stop registration, (h) using electric service without compensation to the utility.

Q: How does the Company wish to define "Tampering" in its Rules and Regulations?

A: The Company seeks to add the following definition for tampering within the definitions Section 1 on Sheet R-5A:

Proposed Item AC on Sheet R-5A defines Tampering is to rearrange, damage, injure, destroy, alter, or interfere with, Company facilities, service wires, electric meters and associated wiring, locking devices, or seals, or otherwise prevent any Company equipment from performing a normal or customary function.

Q: The second general area of proposed changes is amendments to customer fees. Why is the Company seeking changes?

A: The Company recognizes this is a difficult economic time and is not seeking to impose a hardship upon anyone. The Company is seeking to simplify the pole reconnection fee; end after-hours connections; edit other fees definitions to align with the end of after-hour connections; and set a minimum reconnect tampering charge to incent customers to refrain from engaging in tampering activities—which can be dangerous.

Q: Is the Company seeking to amend its Rules and Regulations in support of these changes?

A: Yes. The Company seeks to make the following additions and changes to its Rules and Regulations:

Sheet R-66 Section 2.07 (A) Reconnection Charge:

- Delete "Normal business hours" and replace with "At the meter". No change in the amount of the charge.
- Delete "Outside of normal business hours" and replace with "At the pole". No change to the amount of the charge.

Sheet R-66 Section 4.02 (B) Meter Tampering:

- Delete "Meter".
- Replace "All associated costs" with "All associated costs to reconnect service with a minimum charge of $150.00."

Sheet R-20 Section 2.07 (B) Charge for Reconnection, Connection or Collection:

- Delete "There is no charge for service connections during normal business hours. Where service connections are made outside of normal business hours, the same charge shall apply as for reconnecting service. This Connection Charge shall be assessed to the customer per Section 12 of these Rules."

Q: Will the changes to fees, in an effort to incent customers to use no-fee payment options and refrain from tampering, impact the Company's revenues?

A: The Company believes that there will be little or no impact since the charge is intended to encourage customers to refrain from tampering—a dangerous practice—and to avoid disconnection by proactively working with the Company to determine available options for bringing their account current. However, the Company recognizes some customers will be assessed fees. It is difficult to determine exactly what the impact on revenues will be in the event customers do not change their behavior.

The Company systems do not track whether a reconnection is at the meter, at the pole, or related to tampering, so no specific baseline can be established for the different types of reconnection;

Ending after-hours connection is basically replacing a fifty dollar ($50) fee with either a potential thirty dollar ($30) reconnection fee at the meter, a fifty dollar ($50) reconnection at the pole fee, or a one hundred and fifty dollar ($150) minimum plus costs fee for tampering.

At the pole reconnections will be set at fifty dollars ($50) which, although greater than the previous normal business hours fee of thirty dollars ($30), represents the type of reconnection with the lowest frequency.

Q: Can you provide any analysis as to the number of each of the reconnection categories—at the meter, pole, or tampering?

A: A sense of frequency can be gained by using KCP&L systems that can track reconnection events, and then extrapolating the percentage of the specific reconnection events from KCP&L and then applying percentages to about **[redacted]** reconnection events in GMO, based on an average of 2008 and 2009. The distribution for GMO would look like about **[redacted]** at the pole reconnections; about **[redacted]** at the meter reconnections; and about **[redacted]** tampering reconnections.

Q: By taking into consideration the "estimate" of the distribution between types of reconnections in GMO service territories and the proposed changes in the reconnect fees, do you expect the Company's revenues to increase or decrease?

A: It is likely, taking all the proposed changes in total, that the proposed changes are revenue neutral.

Q: Regarding the third general area of proposed changes the Company is seeking to its Rules and Regulations, what is the variance the Company is seeking on how partial payments are applied against customer accounts?

A: The Company seeks a variance from Rule 4 CSR 240-13.020(11) with amendments to its Rules and Regulations, Sheet R-34, Meter Reading, Billing, and Complaint Procedures. In Section 6.01(C), Billing and Reading of Meters, I propose the deletion of the following language:

> "If partial payment is made, Company shall first credit all payments to the balance outstanding for utility charges, based upon the age of the receivable, with the credit being applied to the oldest receivable first.",

I propose the addition of the following language:

> "If a partial payment is made on a billing including only current charges, the Company shall first credit all payments to the balance outstanding for electric charges before crediting a deposit. If a partial payment is made on a billing which includes a previous balance, the Company will credit all payments first to previous electric charges, then to previous deposit charges before applying any payment to current charges. (This section contains a variance from Rule 4 CSR 240-13.020(11).)"

Q: Why is the Company requesting this variance and changes in the language to its partial payment rule?

A: A strict interpretation of Rule 4 CSR 240-13.020(11) can result in an interruption to service in a situation where the Company's proposed posting policies would not. The requested waiver and amended rule's posting requirement would benefit its residential customers.

Specifically, the Company proposes the following posting sequence:

> 1) electric arrears, 2) deposit arrears, 3) deferred accounts receivable, 4) current electric, 5) deposit billed amount, 6) other arrears, 7) other charges, 8) excess facilities, 9) merchandise.

Furthermore, the requested variance is consistent with the Commission's March 21, 1995, Order granting the same variance to KCP&L in Case No. EO-95-117.

VIII. TRANSMISSION TRACKER

Q: What is the Company's proposal regarding a transmission tracker?

A: In the event the Commission denies the requested change to the FAC mechanism outlined on Schedule TMR2010-1 FAC 4CSR240, whereby transmission costs are included in the FAC, the Company requests that a transmission tracking mechanism be authorized in this rate proceeding for the purpose of ensuring appropriate recovery of transmission costs. GMO and KCP&L currently have similar tracking mechanisms for their pension costs. Other utilities in the state have similar tracking mechanisms, such as Empire District Electric Company's Vegetation Management/Infrastructure Inspection trackers and AmerenUE's SO_2 tracker. Trackers are valuable tools for costs that are material and that fluctuate significantly from year-to-year. Use of the tracker ensures that in the years between rate cases the utility does not under-recover or over-recover its costs.

Q: Are any transmission costs currently included in the FAC?

A: Only the portion of transmission costs attributable to off-system sales is included in the current FAC. The Company's proposed changes to the FAC in this case, discussed earlier in this testimony and documented on Schedule TMR2010-1 FAC 4CSR240, would incorporate all remaining transmission costs (i.e., transmission costs attributable to native load and firm sales).

Q: Why would a tracker be appropriate for GMO's transmission costs in the event the requested changes to the FAC are denied?

A: Transmission costs can vary significantly from year-to-year, and such costs are a material cost of service component. Historically, transmission costs have fluctuated due to load fluctuation, both native and off-system. An added factor in the coming years relates to the Southwest Power Pool's ("SPP") base plan funding plans, which could increase the Company's costs dramatically in coming years.

Q: Please discuss base plan funding.

A: SPP's expansion plan proposes regional transmission additions and includes a detailed list of projects in order to achieve the plan. A major portion of the expansion plan includes those projects that are termed "base plan upgrades," which are those transmission additions required to meet the mandatory North American Electric Reliability Corporation and SPP reliability standards and to provide firm transmission service from designated power resources of SPP member companies. Due to the nature of the interconnected transmission system, these base-plan transmission additions produce reliability and transmission service benefits across the SPP region. Therefore, SPP employs a cost allocation methodology to provide fair and equitable sharing of costs for base-plan transmission additions. The SPP cost allocation calls for one-third of the project cost to be shared by all SPP members, and the remaining two-thirds of the project cost to be allocated among the members that directly benefit from the project. Furthermore, SPP approved a "balanced portfolio" of transmission projects in 2009, totaling over $700 million in initial cost, which will be financed through charges on all load in the SPP region. Finally, the category of base plan upgrades is in the process of expanding substantially due to SPP's April 19, 2010 filing with Federal Energy Regulatory Commission ("FERC") to apply a "highway-byway" cost allocation methodology that will allocate the full cost of transmission projects above 300 kV to all load in the region.

Q: **What factors are driving the increased funding in this area?**

A: A major factor is the push for renewable energy sources in the region, in particular wind power. Significant transmission upgrades are necessary to capture the full wind potential in the region. Another major driver of new upgrades is the need to reduce congestion on key transmission paths in order to facilitate more efficient power markets.

Q: **How do the Company's projected transmission costs compare to historical levels?**

A: Schedule TMR2010-4 provides historical levels.

Q: **What types of costs are included on this schedule?**

A: This schedule includes FERC account 565 costs (standard point-to-point transmission charges and base plan funding), SPP Schedule 1-A fees charged to accounts 561 and 575, and FERC Schedule 12 fees charged to account 928.

Q: **Are these the same costs that the Company proposes to be included in a transmission tracker?**

A: Yes, they are.

Q: **How does the Company propose that a transmission tracker be implemented?**

A: We propose that transmission costs, as defined in this tracker, be set in this rate proceeding at $17,228,411 (MPS) and $1,409,049 (L&P). The Company would then track its actual charges on an annual basis against this amount, with any excess transferred to a regulatory asset (account 182) and any shortfall set up as a regulatory liability (account 254).

Q: Is this amount supported by other Company witnesses in this case?

A: Yes, Company witness John Weisensee supports this amount in his discussion of adjustments CS-45 (Transmission of Electricity by Others), CS-85 (Regulatory Assessments-Schedule 12 Fees) and CS-86 (Schedule 1-A Fees).

Q: How would the regulatory asset or liability be reflected in GMO's next rate case?

A: We propose that the regulatory asset or liability be amortized to cost of service over five years in the Company's next rate proceeding, with the unamortized balance included in rate base.

Q; Is this proposed treatment consistent with the Company's other regulatory tracker, the pension tracker?

A: Yes, it is.

IX. RENEWABLE ENERGY STANDARD

Q: Has the Company requested a similar tracker for the RES, also know as "Proposition C"?

A: No. The Company initially filed an application for an accounting authority order in Case No. EU-2010-0194, requesting authority to defer costs associated with the implementation of the RES law. The Company later withdrew its application in anticipation of a favorable rulemaking to address the Company's concerns and in expectation of this filing.

Q: Is a rule currently in place addressing the RES?

A: No. At the writing of this testimony, the Commission has not enacted a rule regarding the RES.

Q: Has the Company included any RES compliance costs in its revenue requirement in this rate proceeding?

A: Yes, a solar purchased power agreement that qualifies as a renewable energy resource has been included in annualized purchase power expense (adjustment CS-25) sponsored by Company witness Burton L. Crawford. Additionally, solar rebate and renewable energy credit tracking costs have been included in annualized O&M expense (adjustment CS-116) sponsored by Company witness John P. Weisensee.

X. MISSOURI ENERGY EFFICIENCY INVESTMENT ACT OF 2009

Q: Is a rule currently in place addressing the MEEI also known as Senate Bill 376?

A: No. At the writing of this testimony, the Commission has not enacted a rule regarding MEEI. MPSC Staff has a draft rule it has prepared and is currently conducting workshops regarding the law and proposed rulemaking.

Q: What has the Company done in this filing to address MEEI?

A: The Company has not taken any action in this filing beyond what is currently in place and was established in the last two rate cases. KCP&L hopes that rules will become effective in sufficient time prior to the conclusion of this case and will become part of the outcome in this proceeding.

Q: What are the policy goals of MEEI?

A: As set out in the law, there are three public policy goals. They are:

1. Encourage more efficient energy use and cost-effective demand-side programs;

2. Have substantial justice between utilities and their customers;
3. Value demand-side investments equal to traditional investments in supply and delivery infrastructure and allow recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs and, in doing so:
    a. Provide timely cost recovery for utilities;
    b. Ensure that utility financial incentives are aligned with helping customers use energy more efficiently and in a manner that sustains or enhances utility customers' incentives to use energy more efficiently; and
    c. Provide timely earnings opportunities associated with cost-effective measurable and verifiable efficiency savings.

Q: Does the current mechanism filed in the case accomplish these policy goals?

A: No. From the Company's perspective, the current regulatory accounting mechanism does not adequately address the policy goals set out in the law. Specifically, the current mechanism does not provide timely recovery or earnings opportunities, nor does it sufficiently encourage the implementation of energy efficiency programs by the utility. It is our expectation that the rule that comes out of the MEEI rulemaking process will address these goals and will more adequately address energy efficiency programs and cost recovery.

Q: Is the Company in a position to implement the rule that comes out of the MEEI rulemaking process?

A: Yes. It is our hope that the rule will become effective prior to the conclusion of the case and will be implemented as part of this case.

Q: How has DSM cost recovery been handled in prior Aquila/GMO rate cases?

A: The Stipulation and Agreement as to Certain Issues in Case No. ER-2007-0004, approved by the Commission in its Report and Order dated May 17, 2007, stated that:

The Signatories agree that for ratemaking purposes Aquila will defer the costs of DSM programs in Account 186 and calculate allowance for funds used during construction (AFUDC) annually... The prudently-incurred costs included in the Account 186 balance will be amortized over a ten (10) year period. When new rates go into effect reflecting amortization recovery as a result of future general rate proceedings, the prudently-incurred costs included in the Account 186 balance will be added to rate base, Aquila will stop accruing AFUDC on the amount included in rate base, and Aquila will begin amortizing the balance. Additional DSM program costs incurred after the effective date of a final Report and Order in the initial general rate proceeding following Case No. ER-2007-0004 will be treated in the same manner, but will be deferred in a different sub-account by vintage.

Q: Was DSM treatment addressed in the final order in Case No. ER-2009-0090?

A: Yes, the Non-Unanimous Stipulation and Agreement in that case, approved by the Commission in its Order Approving Non-Unanimous Stipulations and Agreements and Authorizing Tariff Filing dated June 10, 2009, included a DSM section worded identical to the wording in the Case No. ER-2007-0004 Stipulation and Agreement.

Q: Please explain GMO's current portfolio of DSM programs.

A: GMO's portfolio is identical to the KCP&L Missouri program portfolio. It is our intention to offer the same programs across all jurisdictions so that all customers are able to benefit equally and to eliminate confusion. Beginning in 2008, GMO submitted each program to the Commission for review and approval ultimately implementing a portfolio of programs including two affordability programs, ten energy efficiency programs, and two demand response programs.

Q: Have these programs been successful?

A: Yes, for the most part, the programs have been successful. The formal evaluation reports are due to be conducted beginning later this year. Overall, customer response to GMO's portfolio of programs has been positive. GMO has had success with its demand response programs and has secured 27.5 MW of curtailable load through March 31, 2010 from its Missouri customers. Our energy efficiency programs have also had good success and GMO estimates that 20,526 MWh have been saved through March 31, 2010 from GMO customers. GMO's affordability programs have had mixed success; the Low Income Weatherization program has been successful, but the Affordable New Homes program has been a challenge with respect to participation. GMO estimates that 421 MWh have been saved in Missouri as a result of its affordability programs through March 31, 2010.

Q: Please discuss the proposed DSM program portfolio and how the programs fit into the Company's overall resource plan.

A: GMO's proposed DSM program portfolio is an integral part of its plan to meet the electricity needs of our customers now and in the future. The proposed energy and demand reductions that are the subject of this proceeding will be reflected in GMO's load and resource requirements. This resource serves as a bridging technology at a lower cost than alternative resources. GMO's existing and expanded energy efficiency and peak demand reduction efforts are consistent with its focus to meet our customers' needs in a balanced, cost-effective and environmentally responsible manner.

Q: Are the GMO DSM programs considered "pilot" programs with a specific expiration date?

A: There is some uncertainty regarding this issue. Although the tariffs do not specifically reference pilot programs, many of these programs were authorized using the supporting budget information from the Integrated Resource Plan, some even including annual budget amounts within the tariffs. This raises questions about the status of these programs once the five-year period for each expires or when the budgeted amounts for the programs have been spent. It is the hopes that with the establishment of a rulemaking that adequately provides recovery, all of the programs currently in the portfolio will become permanent.

Q: Does the current recovery mechanism adequately recover the cost of the DSM programs and sufficiently provide benefits to customers and shareholders?

A: No, it does not. The current method of recovery is inadequate, particularly to shareholders. The legislature and ultimately the Governor of Missouri recognized in 2009 that a law should be established to address energy efficiency DSM programs. This resulted in the passage of SB 376, the Missouri Energy Efficiency Investment Act of 2009 (Section 393.1075, RSMo Supp 2009).

Q: Is GMO seeking to change the structure of its cost recovery mechanism in this proceeding?

A: As I stated previously, the Company is not seeking to change the cost recovery mechanism in its initial filing. It is the Company's hope that by the time the tariffs in this case are effective, a rulemaking will be implemented in the state that addresses SB 376.

At the writing of this testimony the Staff and other parties are holding workshops and the Company is taking an active role in this rulemaking process.

The Company anticipates the new rules will address the uncertain environment of DSM programs by implementing a comprehensive cost recovery approach. The Company hopes that the Commission changes the current method used to recover the costs of implementing these DSM programs.

For purposes of this filing, the Company has included unamortized DSM costs in rate base and included a ten-year amortization of those costs in cost of service, as reflected in Schedule JPW2010-2, adjustments RB-100 and CS-100, respectively.

Q: Does that conclude your testimony?

A: Yes.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Application of KCP&L Greater Missouri Operations Company to Modify Its Electric Tariffs to Effectuate a Rate Increase	)))	Docket No. ER-2010-____

AFFIDAVIT OF TIM M. RUSH

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Tim M. Rush, being first duly sworn on his oath, states:

1. My name is Tim M. Rush. I work in Kansas City, Missouri, and I am employed by Kansas City Power & Light Company as Director, Regulatory Affairs.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of KCP&L Greater Missouri Operations Company consisting of twenty-eight (28) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Tim M. Rush

Tim M. Rush

Subscribed and sworn before me this 28th day of May, 2010.

Nicole A. Wehry

Notary Public

My commission expires: Feb. 4, 2011

" NOTARY SEAL "
Nicole A. Wehry, Notary Public
Jackson County, State of Missouri
My Commission Expires 2/4/2011
Commission Number 07391200

Requirements to Continue or Modify the Fuel Adjustment Clause

4 CSR 240-3.161 (3) When an electric utility files a general rate proceeding following the general rate proceeding that established its RAM as described by 4 CSR 240-20.090(2) in which it requests that its RAM be continued or modified, the electric utility shall file with the commission and serve parties, as provided in sections (9) through (11) in this rule the following supporting information as part of, or in addition to, its direct testimony:

(A) An example of the notice to be provided to customers as required by 4 CSR 240-20.090(2)(D):

See Schedule TMR2010-2.

(B) If the electric utility proposes to change the identification of the RAM on the customer's bill, an example customer bill showing how the proposed RAM shall be separately identified on affected customers' bills, including the proposed language, in accordance with 4 CSR 240-20.090(8):

No change is proposed.

(C) Proposed RAM rate schedules:

See Schedule TMR2010-3.

(D) A general description of the design and intended operation of the proposed RAM:

The design and intended operation of the Fuel Adjustment Clause (FAC) is the same as approved in Case No. ER-2009-0090. The change proposed in this filing is for the amounts contained in base rates. Some key features of the FAC include:

- The FAC factor is based upon historical differences between the cost of fuel, energy and transmission costs net of off-system sales revenue built into base rates and the actual cost of fuel, energy and transmission net of off-system sales revenue.
- There is 95% recovery of the difference between these actual costs and the amounts built into base rates.
- Items considered in the FAC are variable generating plant fuel costs, purchased power energy charges, emission allowance costs, hedging costs, and transmission costs. Off-system sales revenues are netted against these costs and carrying costs are calculated monthly at the Company's short term debt rate.
- The under or over recovery will be accumulated for 6 months. The collection period for the accumulation is 12 months.
- The base amounts for the current tariff are $.02348 per kWh for KCP&L (MPS) and $.01642 per kWh for KCP&L (L&P).
- The proposed amounts are $0.02626 per kWh for KCP&L (MPS) and $0.01715 per kWh for KCP&L (L&P)
- This change in the base rates is not a proposed rebasing rather an adjustment to include proposed new costs within the fuel adjustment mechanism.

(E) A complete explanation of how the proposed RAM is reasonably designed to provide the electric utility a sufficient opportunity to earn a fair return on equity:

See Direct Testimony of Samuel C. Hadaway.

(F) A complete explanation of how the proposed FAC shall be trued-up to reflect over or

under-collections, or the refundable portion of the proposed IEC shall be trued-up, on at least an annual basis:

Each month there is an accrual to reflect the over/under recovered current month FAC fuel costs in General Ledger Account 182380-Accrued Fuel Clause. The accrual calculation is Total FAC Actual Energy Costs less Base Energy Costs times 95%.

After defined 6 month accumulation periods (June-November and December-May) a filing in accordance with 4 CSR 240-20.090(4) is made with the Missouri Public Service Commission requesting a new cost adjustment factor. The collection periods for these FAC factors are 12 month periods (March-February and September-August).

Activity in account 182380 is manually tracked by accumulation period and separately identifies the accrual recovery, interest and over/under recovery balance for each open accumulation period.

After the 12 month recovery period is complete, a true-up filing is made and any remaining over/under recovery identified is included as part of the next FAC filing.

(G) A complete description of how the proposed RAM is compatible with the requirement for prudence reviews:

4 CSR 240-20.090 sets forth the definitions, structure, operation, and procedures relevant to a Fuel Adjustment Clause. Section (7) is specific to prudence reviews, requiring a review no less frequently than at eighteen (18)-month intervals.

The Company agrees that prudence reviews should occur no less frequently than at 18 month intervals. This requirement is also in the FAC tariff.

It is anticipated that parties to any prudence review proceeding would apply the standard of determining whether decisions were prudent given the facts known at the time those decisions were made, as opposed to a "hindsight" review. If Staff or other parties believe that the evidence supports a prudence adjustment, they have the opportunity to bring that proposal to the Commission for an evidentiary hearing and decision.

(H) A complete explanation of all the costs that shall be considered for recovery under the proposed RAM and the specific account used for each cost item on the electric utility's books and records:

The Federal Energy Regulatory Commission (FERC) Code of Federal Regulations is the basis for the Company's accounting codes. Fuel used in the production of steam for the generation of electricity (Coal Plants) is included in FERC account 501. Fuel used in other power generation (Combustion Turbines) is included in FERC account 547. Purchased Power is in FERC account 555. Transmission of electricity by others is included in FERC account 565. SPP transmission costs and fees are included in FERC accounts 561, 575, and 928. Sales for resale are recorded in FERC account 447. The following six digit Company accounts expand from the FERC accounts, representing native load (NL) and sales for resale (SFR), and are included in the FAC.

General Ledger Account	Expense
501000	NL Coal and Freight Costs (Variable)
501001	NL Coal and Freight Costs (Variable)
501002	NL Tire Costs (Variable)
501009	NL Coal and Freight Costs (Variable)
501010	NL Coal Inventory Adj.
501012	NL Biofuels
501020	NL Coal and Freight Costs (Variable)
501026	NL Coal Freeze & Dust Treatment

501027	NL Coal Freeze & Dust Treatment
501030	SFR Coal & Freight Costs
501100	NL Oil Costs
501200	NL Gas
501220	NL Propane
501300, 501301, 501302	NL Additives
501400	NL Residuals Costs
501450	NL Residuals Costs
504100, 504102	Contra Steam Customer Fuel Costs
504103	Contra Steam Customer Gas Costs
504104	Contra Steam Customer Oil Costs
509000, 509002, 509003	Emission Allowances
547001	NL Oil
547002	NL Gas Costs & Transportation (Variable)
547004	NL Gas Adjustments
547010	NL Oil Adjustments
547020	NL Gas Costs & Transportation (Variable)
547030	SFR Gas Costs & Transportation (Variable)
547105	Hedge Settlements
555000, 555020, 555021	NL Purchased Power-Energy
555005	Purchased Power-Capacity (Short-term ONLY)
555030, 555031	SFR Purchased Power-Energy
555035	SFR Purchased Power - WAPA
561400	Trans Op-Schd,Contr & Dis Serv
561800	Trans Op-Reli Plan&Std Dv-RTO
565000	Transm Oper-Elec Tr-By Others
565021	Transm Oper-elec Tr-Interunit
565027	Transm Oper-Elec Tr-Demand
565030	SFR Transmission
575700	Trans Op-Mkt Mon&Comp Ser-RTO
928003	Reg Comm Exp-FERC Assessment

General Ledger Account	Revenue
447002	Bulk Power Sales
447030	SFR Off-system Sales
447035	SFR Off System Sales - WAPA

Accounts provided were known as of the time of this filing; however, they may be revised in the future as business needs arise.

(I) A complete explanation of all the revenues that shall be considered in the determination of the amount eligible for recovery under the proposed RAM and the specific account where each such revenue item is recorded on the electric utility's books and records:

FAC revenues are billed as a separate line item on a customer's bill and all FAC revenue is recorded in the following revenue accounts to accurately track revenues and facilitate the review process. In addition, the CIS+ billing system tracks the FAC billed line item. FAC revenues are reported separately on CIS+ Revenue Reports.

General Ledger Account	Revenue
440001	Residential Electric Revenue
442001	Commercial Electric Revenue
442202	Industrial Firm Electric Revenue
444001	Sales Street Lighting
445001	Sales Public Authority Electric

Billed FAC revenues are initially recorded as revenue (as shown above) when processed by CIS+. Accounting reverses the Billed FAC revenue exactly and offsets the Accrued Fuel Clause account (182380). The reclassification of the Billed FAC revenue is through a separate set of revenue accounts, as follows:

General Ledger Account	Revenue
440009	Residential Electric Revenue FAC Rcvy
442009	Commercial Electric Revenue FAC Rcvy
442209	Industrial Firm Electric Revenue FAC Rcvy
444009	Sales Street Lighting FAC Rcvy
445009	Sales Public Authority Electric FAC Rcvy

Current period over/under accrual FAC revenues are booked as defined above as Total FAC Actual Energy Costs less Base Energy Costs times 95% with the resulting accrual offset in General Ledger Account 182380, Accrued Fuel Clause. The over/under accrued FAC revenues is booked to a separate set of revenue accounts, as follows:

General Ledger Account	Revenue
440007	Residential Electric Revenue FAC/IEC Unbilled
442007	Commercial Electric Revenue FAC/IEC Unbilled
442205	Industrial Firm Electric Rev FAC/IEC Unbilled
444005	Sales Street Lighting FAC/IEC Unbilled
445005	Sales Public Authority Electric FAC/IEC Unbill

This accounting process, and the information used to support the recording of these entries, creates a paper audit trail to enable the audit of the accounts.

(J) A complete explanation of any incentive features designed in the proposed RAM and the expected benefit and cost each feature is intended to produce for the electric utility's shareholders and customers:

In the Report and Order for Case No. ER-2007-0004 issued May 17, 2007, the Commission explains the reasoning for allowing only 95% of FAC eligible costs to be collected from customers.

"The Commission also finds after-the-fact prudence reviews alone are insufficient to assure Aquila will continue to take reasonable steps to keep its fuel and purchased power costs down, and the easiest way to ensure a utility retains the incentive to keep fuel and purchased power costs down is to not allow a 100% pass through of those costs.

The Commission finds allowing Aquila to pass 95% of its prudently incurred fuel and purchased power costs, above those included in its base rates, through its fuel adjustment clause is appropriate. With a 95% pass-through, the Commission finds Aquila will be protected from extreme fluctuations in fuel and purchased power cost, yet retain a significant incentive to take all reasonable actions to keep its fuel and purchased power costs as low as possible, and still have an opportunity to earn a fair return on its investment." (page 54)

"The Commission concludes that a 95% pass-through would not violate Section 386.266.4(1), in that it would still afford Aquila a sufficient opportunity to earn a fair return on equity." (page 55)

The 95% pass-through feature remained unchanged in the settlement of Rate Case. ER-2009-0090.

The 5% loss to shareholders for the most recent two accumulation periods is approximately $2.2 mil.

(K) A complete explanation of any rate volatility mitigation features in the proposed RAM:

The hedge program costs and benefits, as discussed in the Direct Testimony of Wm. Edward Blunk, can mitigate fuel price volatility. In addition, accumulating the FAC adjustment for a 6 month period with a corresponding 12 month revenue recovery period lessens rate volatility.

(L) A complete explanation of any feature designed into the proposed RAM or any existing electric utility policy, procedure, or practice that can be relied upon to ensure that only prudent costs shall be eligible for recovery under the proposed RAM:

The Company's FAC expenses are subject to periodic Prudence Reviews to ensure that only prudently-incurred fuel and purchased power costs are collected from customers through the FAC.

Rules and procedures for contracts are outlined in the Sarbanes Oxley documentation.

Rules and procedures for the hedging program are in the Risk Management Policy.

(M) A complete explanation of the specific customer class rate design used to design the proposed RAM base amount in permanent rates and any subsequent rate adjustments during the term of the proposed RAM:

A class cost of service study and rate design change were not a part of ER-2007-0004 approving the FAC, ER-2009-0090 continuing the FAC, or this current rate request. The existing rate design is maintained by allocating the rate increase and the FAC as a percentage increase to all classes.

As required, the FAC allocates cost by voltage level using commission approved allocation methods.

(N) A complete explanation of any change in business risk to the electric utility resulting from implementation of the proposed RAM in setting the electric utility's allowed return in any rate proceeding, in addition to any other changes in business risk experienced by the electric utility:

See Direct Testimony of Samuel C. Hadaway.

(O) A description of how responses to subsections (B) through (N) differ from responses to subsections (B) through (N) for the currently approved RAM:

The recovery of propane has been added to the tariff. Fuel used for fuel handling has been removed from the tariff. Transmission costs and fees have been added to the tariff. The 5% amount not recovered has been updated.

(P) The supply-side and demand-side resources that the electric utility expects to use to meet its loads in the next four (4) true-up years, the expected dispatch of those resources, the reasons why these resources are appropriate for dispatch and the heat rates and fuel types for each supply-side resource; in submitting this information, it is recognized that supply- and demand-side resources and dispatch may change during the next four (4) true-up years based upon changing circumstances and parties will have the opportunity to comment on this information after it is filed by the electric utility:

The expected resource dispatch levels for the next four years and fuel types can be found in Schedule TMR2010-5. Heat rates results can be found in the testimony of Burton L. Crawford. As stated in (R) below, one objective of the planning process is to identify the least cost resources. These resources are dispatched on an economic basis. This means the least cost resources are dispatched before higher cost resources. The 2009 GMO Integrated Resource Plan ("IRP"), also referenced in (R) below, considered both demand-side and supply-side resources to meet future customer needs. GMO has engaged Summit Blue, KEMA (formerly RLW Analytic), Integral Analysis and Morgan Market Partners to recommend demand-side resource programs. The 2009 GMO IRP recommended pursuing the cost effective programs. These were considered in the analysis and included in the eventual Preferred Plan. Demand-side and supply-side resources which are identified in the IRP do not remain static over time. As implementation schedules change, new candidate resources are identified, and as market conditions change, GMO may evaluate this new information. After the evaluation is conducted, GMO may make changes to the implementation plan that deviates from the published IRP.

(Q) The results of heat rate tests and/or efficiency tests on all the electric utility's nuclear and non-nuclear steam generators, HRSG, steam turbines and combustion turbines conducted within the previous twenty four (24) months:

See Direct Testimony of Burton L. Crawford.

(R) Information that shows that the electric utility has in place a long-term resource planning process, important objectives of which are to minimize overall delivered energy costs and provide reliable service:

GMO has a long-term resource planning process. The electric utility resource plan produced by the process is also known as an integrated resource plan or IRP. An objective of this planning process is to identify the least cost and preferred resource plans while maintaining adequate capacity reserves for reliability. GMO prepared and filed its latest IRP report in August 2009. This IRP filing is currently in settlement negotiations under Docket EO-2009-0237. Under the current IRP rule, the next GMO IRP is to be filed in August 2012. This date may change with the adoption of a new IRP rule by the Commission.

(S) If emissions allowance costs or sales margins are included in the RAM request and not in the electric utility's environmental cost recovery surcharge, a complete explanation of forecasted environmental investments and allowances purchases and sales; and

See Direct Testimony of Wm. Edward Blunk for the discussion of the allowance purchases and sales and the direct testimony of Burton L. Crawford for the explanation of forecasted environmental investments.

(T) Any additional information that may have been ordered by the commission to be provided in the previous general rate proceeding:

Within the Nonunanimous Stipulation and Agreement from the last general rate case, Rate Case No. ER-2009-0090, the Signatories agreed that to aid in FAC tariff, prudence and true-up reviews, GMO would submit to Staff the following:

- As part of the information GMO submits when it files a tariff modification to change its cost adjustment factor ("CAF"), GMO's calculation of the interest included in the proposed CAF;
- In addition to the monthly reports required by 4 CSR 240-3.161(5), GMO's Southwest Power Pool ("SPP") Energy Imbalance Service ("EIS") market settlements and revenue neutrality uplift charges;
- At GMO's corporate headquarters or at some other mutually agreed upon place within a mutually agreed upon time for review, a copy of each and every coal and transportation contract GMO has that is in effect;
- Within 30 days of the effective date of each and every coal and transportation contract GMO enters into, both notice to the Staff of the contact and, at GMO's corporate headquarters or at some other mutually agreed upon place, the contracts for review;
- At GMO's corporate headquarters or at some other mutually agreed upon place within a mutually agreed upon time, a copy for review of each and every natural gas contract GMO has that is in effect;
- Within 30 days of the effective date of each and every natural gas contract GMO enters into, both notice to the Staff of the contract and at GMO's corporate headquarters or at some other mutually agreed upon place a copy of the contract for review;
- A copy of each and every GMO hedging policy that is in effect for Staff to retain;

- Within 30 days of any change in GMO hedging policy, a copy of the changed hedging policy for Staff to retain;
- A copy of GMO's internal policy for participating in the SPP EIS market, including any GMO sales/purchases from that market for Staff to retain;
- If GMO revises any internal policy for participating in the SPP EIS market, within 30 days of that revision, a copy of the revised policy with the revisions identified for Staff to retain; and
- In addition to supplying the information required by 4 CSR 240-3.190(3) for any accidents occurring at a power plant involving serious physical injury or death or property damage in excess of $100,000, the information for every incident at a power plant in which GMO has any ownership interest that involves serious physical injury or death or property damage in excess of $100,000 in the aggregate.

Important Notice

KCP&L Greater Missouri Operations Company ("Company" or "GMO") has filed a rate increase request with the Missouri Public Service Commission ("PSC"). The increase would total approximately 14.4 percent in the territory served as MPS and approximately 13.9 percent in the territory served as L&P.

For the average MPS residential customer the proposed increase would be approximately $14.86 per month. For the average L&P residential customer the proposed increase would be approximately $12.82 per month.

The Company has also asked the PSC to continue the Fuel Adjustment Clause ("FAC"). The FAC allows the Company to adjust customers' bills two times per year based on the varying cost of fuel and power purchased in the current volatile market. Any increase or decrease in fuel costs is reflected in the FAC. This means the customer bill is based on more current fuel costs.

A local public hearing (or evidentiary hearing) has been set before the PSC at ___o'clock, on (date) at _________, (address), City, Missouri. The hearing will be held in a facility that meets the accessibility requirements of the Americans with Disabilities Act. Any person who needs additional accommodations to participate in this hearing should call the Public Service Commission's hotline at ______________ (voice) or Relay Missouri at 711 before the hearing.

Consumers who are unable to attend the local public hearing and wish to make written comments may contact the Office of the Public Counsel, Governor Office Building, 200 Madison Street, Suite 650, P.O. Box 2230, Jefferson City, Missouri 65102-2230, telephone (866) 922-2959, e-mail opcservice@ded.mo.gov or the Missouri Public Service Commission, P.O. Box 360, Jefferson City, Missouri 65102, telephone 800-392-4211, e-mail pscinfo@psc.mo.gov.

FUEL ADJUSTMENT CLAUSE ELECTRIC
(Applicable to Service Provided May 4, 2011 and Thereafter)

DEFINITIONS

ACCUMULATION PERIODS, FILING DATES AND RECOVERY PERIODS:

The two six-month accumulation periods each year through May 1, 2015, the two corresponding twelve-month recovery periods and the filing dates will be as shown below. Each filing shall include detailed work papers in electronic format to support the filing.

Accumulation Periods	**Filing Dates**	**Recovery Periods**
June – November	By January 1	March – February
December – May	By July 1	September – August

A recovery period consists of the billing months during which the Cost Adjustment Factor (CAF) for each of the respective accumulation periods are applied to retail customer billings on a per kilowatt-hour (kWh) basis.

COSTS AND REVENUES:

Costs eligible for the Fuel Adjustment Clause (FAC) will be the Company's allocated Jurisdictional costs for the fuel component of the Company's generating units, including costs associated with the Company's fuel hedging program; purchased power energy charges, including applicable transmission fees; applicable Southwest Power Pool (SPP) costs, and emission allowance costs - all as incurred during the accumulation period. These costs will be offset by off-system sales revenues, applicable net SPP revenues, and any emission allowance revenues amortized during the accumulation period. Eligible costs do not include the purchased power demand costs associated with purchased power contacts in excess of one year.

APPLICABILITY

The price per kWh of electricity sold to retail customers will be adjusted (up or down) periodically subject to application of the FAC mechanism and approval by the Missouri Public Service Commission.

The CAF is the result of dividing the Fuel and Purchased Power Adjustment (FPA) by forecasted retail net system input (RNSI) during the recovery period, expanded for losses, rounded to the nearest $.0001, and aggregating over two accumulation periods. A CAF will appear on a separate line on retail customers' bills and represents the rate charged to customers to recover the FPA.

FUEL ADJUSTMENT CLAUSE ELECTRIC (CONTINUED)
(Applicable to Service Provided May 4, 2011 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 95% * ((TEC – B) * J) + C + I

CAF = FPA/RNSI

Single Accumulation Period Secondary Voltage CAF_{Sec} = CAF * XF_{Sec}

Single Accumulation Period Primary Voltage CAF_{Prim} = CAF * XF_{Prim}

Annual Secondary Voltage CAF =
Aggregation of the Single Accumulation Period Secondary Voltage CAFs still to be recovered

Annual Primary Voltage CAF =
Aggregation of the Single Accumulation Period Primary Voltage CAFs still to be recovered

Where:

FPA = Fuel and Purchased Power Adjustment

CAF = Cost Adjustment Factor

95% = Customer responsibility for fuel variance from base level.

TEC = Total Energy Cost = (FC + EC + PP + TC - OSSR):

FC = Fuel Costs Incurred to Support Sales:

- The following costs reflected in Federal Energy Regulatory Commission (FERC) Account Numbers 501 & 504: coal commodity and railroad transportation, switching and demurrage charges, applicable taxes, adders and adjustments, natural gas costs, alternative fuel (i.e. tires and bio-fuel), fuel additives, quality adjustments assessed by coal suppliers, fuel hedging cost (hedging is defined as realized losses and costs minus realized gains associated with mitigating volatility in the Company's cost of fuel, including but not limited to, the Company's use of futures, options and over-the-counter derivatives including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps), fuel oil adjustments included in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs, propane costs, ash disposal revenues and expenses, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses in Account 501.

FUEL ADJUSTMENT CLAUSE ELECTRIC (CONTINUED)
(Applicable to Service Provided May 4, 2011 and Thereafter)

- The following costs reflected in FERC Account Number 547: natural gas generation costs related to commodity, oil, transportation, storage, fuel losses, hedging costs, fuel additives, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses, broker commissions and fees in Account 547.

EC = Net Emissions Costs:

- The following costs reflected in FERC Account Number 509 or any other account FERC may designate for emissions expenses in the future: Emission allowances costs offset by revenues from the sale of emission allowances.

PP = Purchased Power Costs:

- Purchased power costs reflected in FERC Account Numbers 555: Purchased power costs, settlement proceeds, insurance recoveries, and subrogation recoveries for increased purchased power expenses in Account 555, excluding capacity charges for purchased power contracts with terms in excess of one (1) year.

TC = SPP Costs:

- Transmission and SPP costs included in FERC Account Numbers 561, 565, 575, and 928: Base plan and balanced portfolio regional and zonal charges assessed by SPP, point-to-point charges, and annual fees.

OSSR = Revenues from Off-System Sales:

- Revenues from Off-system Sales in FERC Account Number 447:
- Revenues from Off-system Sales shall exclude long-term full & partial requirements sales associated with GMO.

B = Base energy costs are costs as defined in the description of TEC (Total Energy Cost). Base Energy costs will be calculated as shown below:
L&P NSI x Applicable Base Energy Cost
MPS NSI x Applicable Base Energy Cost

J = Energy retail ratio = Retail kWh sales/total system kWh
Where: total system kWh equals retail and full and partial requirements sales associated with GMO.

C = Under / Over recovery determined in the true-up of prior recovery period cost, including accumulated interest, and modifications due to prudence reviews

I = Interest on deferred electric energy costs calculated at a rate equal to the weighted average interest paid on short-term debt applied to the month-end balance of deferred electric energy costs

FUEL ADJUSTMENT CLAUSE ELECTRIC (CONTINUED)
(Applicable to Service Provided May 4, 2011 and Thereafter)

RNSI = Forecasted retail net system input in kWh for the Recovery Period

XF = Expansion factor by voltage level
XF_{Sec} = Expansion factor for lower than primary voltage customers
XF_{Prim} = Expansion factor for primary and higher voltage customers

NSI = Net system input (kWh) for the accumulation period

The FPA will be calculated separately for L&P and MPS, and by voltage level, and the resultant CAF's will be applied to customers in the respective divisions and voltage levels.

APPLICABLE BASE ENERGY COST

Company base energy costs per kWh:
$0.01715 for L&P.
$0.02626 for MPS

TRUE-UPS AND PRUDENCE REVIEWS

There shall be prudence reviews of costs and the true-up of revenues collected with costs intended for collection. FAC costs collected in rates will be refundable based on true-up results and findings in regard to prudence. Adjustments, if any, necessary by Commission order pursuant to any prudence review shall also be placed in the FAC for collection unless a separate refund is ordered by the Commission. True-ups occur at the end of each recovery period. Prudence reviews shall occur no less frequently than at 18 month intervals.

FUEL ADJUSTMENT CLAUSE ELECTRIC (CONTINUED)
(Applicable to Service Provided May 4, 2011 and Thereafter)

COST ADJUSTMENT FACTOR

		MPS	L&P
Accumulation Period Ending			
1 Total Energy Cost (TEC)			
2 Base energy cost (B)	-		
3 First Interim Total			
4 Jurisdictional Factor (J)	*		
5 Second Interim Total			
6 Customer Responsibility	*	95%	95%
7 Third Interim Total			
8 Adjustment for Under / Over recovery for prior periods and Modifications due to prudence reviews (C)	+		
9 Interest (I)	+		
10 Fuel and Purchased Power Adjustment (FPA)			
11 RNSI	÷		
12 Fourth Interim Total			
13 Current period CAF_{Prim} (= Line 12 * XF_{Prim})			
14 Previous period CAF_{Prim}	+		
15 Current annual CAF_{Prim}			
16 Current period CAF_{Sec} (= Line 12 * XF_{Sec})			
17 Previous period CAF_{Sec}	+		
18 Current annual CAF_{Sec}			

Expansion Factors (XF):

Network:	Primary	Secondary
MPS	1.041873	1.071233
L&P	1.042138	1.070143

FUEL ADJUSTMENT CLAUSE ELECTRIC
(Applicable to Service Provided Prior to May 4, 2011)

DEFINITIONS

ACCUMULATION PERIODS, FILING DATES AND RECOVERY PERIODS:

The two six-month accumulation periods each year through August 5, 2013, the two corresponding twelve-month recovery periods and the filing dates will be as shown below. Each filing shall include detailed work papers in electronic format to support the filing.

Accumulation Periods	Filing Dates	Recovery Periods
June – November	By January 1	March – February
December – May	By July 1	September – August

A recovery period consists of the billing months during which the Cost Adjustment Factor (CAF) for each of the respective accumulation periods are applied to retail customer billings on a per kilowatt-hour (kWh) basis.

COSTS AND REVENUES:

Costs eligible for the Fuel Adjustment Clause (FAC) will be the Company's allocated Jurisdictional costs for the fuel component of the Company's generating units, including costs associated with the Company's fuel hedging program; purchased power energy charges, including applicable transmission fees; applicable Southwest Power Pool (SPP) costs, and emission allowance costs - all as incurred during the accumulation period. These costs will be offset by off-system sales revenues, applicable net SPP revenues, and any emission allowance revenues collected during the accumulation period. Eligible costs do not include the purchased power demand costs associated with purchased power contacts in excess of one year.

APPLICABILITY

The price per kWh of electricity sold to retail customers will be adjusted (up or down) periodically subject to application of the FAC mechanism and approval by the Missouri Public Service Commission.

The CAF is the result of dividing the Fuel and Purchased Power Adjustment (FPA) by forecasted retail net system input (RNSI) during the recovery period, rounded to the nearest $.0001, and aggregating over two accumulation periods. A CAF will appear on a separate line on retail customers' bills and represents the rate charged to customers to recover the FPA.

FUEL ADJUSTMENT CLAUSE ELECTRIC (CONTINUED)
(Applicable to Service Provided Prior to May 4, 2011)

FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 95% * ((TEC – B) * J) + C + I

CAF = FPA/RNSI

Single Accumulation Period Secondary Voltage CAF_{Sec} = CAF * XF_{Sec}

Single Accumulation Period Primary Voltage CAF_{Prim} = CAF * XF_{Prim}

Annual Secondary Voltage CAF =
Aggregation of the Single Accumulation Period Secondary Voltage CAFs still to be recovered

Annual Primary Voltage CAF =
Aggregation of the Single Accumulation Period Primary Voltage CAFs still to be recovered

Where:

FPA = Fuel and Purchased Power Adjustment

CAF = Cost Adjustment Factor

95% = Customer responsibility for fuel variance from base level.

TEC = Total Energy Cost = (FC + EC + PP - OSSR):

FC = Fuel Costs Incurred to Support Sales:

- The following costs reflected in Federal Energy Regulatory Commission (FERC) Account Numbers 501 & 502: coal commodity and railroad transportation, switching and demurrage charges, applicable taxes, natural gas costs, alternative fuel (i.e. tires and bio-fuel), fuel additives, quality adjustments assessed by coal suppliers, fuel hedging cost (hedging is defined as realized losses and cost minus realized gains associated with mitigating volatility in the Company's cost of fuel, including but not limited to, the Company's use of futures, options and over-the-counter derivatives including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps), fuel oil adjustments included in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs, ash disposal revenues and expenses, fuel used for fuel handling, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses in Account 501.

FUEL ADJUSTMENT CLAUSE ELECTRIC (CONTINUED)
(Applicable to Service Provided Prior to May 4, 2011)

- The following costs reflected in FERC Account Number 547: natural gas generation costs related to commodity, oil, transportation, storage, fuel losses, hedging costs, fuel additives, fuel used for fuel handling, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses, broker commissions and fees in Account 547.

EC = Net Emissions Costs:

- The following costs reflected in FERC Account Number 509 or any other account FERC may designate for emissions expenses in the future: Emission allowances costs and revenues from the sale of SO2 emission allowances.

PP = Purchased Power Costs:

- Purchased power costs reflected in FERC Account Numbers 555, 565, and 575: Purchased power costs, settlement proceeds, insurance recoveries, and subrogation recoveries for increased purchased power expenses in Account 555, excluding SPP and MISO administrative fees and excluding capacity charges for purchased power contracts with terms in excess of one (1) year.

OSSR = Revenues from Off-System Sales:

- Revenues from Off-system Sales shall exclude long-term full & partial requirements sales associated with GMO.

B = Base energy costs are costs as defined in the description of TEC (Total Energy Cost). Base Energy costs will be calculated as shown below:

L&P NSI x Applicable Base Energy Cost
MPS NSI x Applicable Base Energy Cost

J = Energy retail ratio = Retail kWh sales/total system kWh
Where: total system kWh equals retail and full and partial requirements sales associated with GMO.

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FUEL ADJUSTMENT CLAUSE ELECTRIC (CONTINUED)
(Applicable to Service Provided Prior to May 4, 2011)

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NSI = Net system input (kWh) for the accumulation period

The FPA will be calculated separately for L&P and MPS, and by voltage level, and the resultant CAF's will be applied to customers in the respective divisions and voltage levels.

APPLICABLE BASE ENERGY COST

Company base energy costs per kWh:
$0.01642 for L&P.
$0.02348 for MPS

TRUE-UPS AND PRUDENCE REVIEWS

There shall be prudence reviews of costs and the true-up of revenues collected with costs intended for collection. FAC costs collected in rates will be refundable based on true-up results and findings in regard to prudence. Adjustments, if any, necessary by Commission order pursuant to any prudence review shall also be placed in the FAC for collection unless a separate refund is ordered by the Commission. True-ups occur at the end of each recovery period. Prudence reviews shall occur no less frequently than at 18 month intervals.

KCP&L Greater Missouri Operations Company
Transmission Expenses

Account	Account Description	2005	2006	2007	2008	2009	Included in current filing
MPS							
561400	Trans Op-Schd,Contr & Dis Serv	-	1,805,885	2,159,158	3,210,350	137,310	979,269
561800	Trans Op-Reli Plan&Std Dv-RTO	-	6,668	14,030	23,475	127,636	171,019
565000	Transm Oper-Elec Tr-By Others	12,117,025	20,861,920	-	2,971,674	3,445,095	5,711,708
565020	Trans of Electricity by Others	-	-	14,615,281	1,442,150	-	-
565021	Transm Oper-Elec Tr-Interunit	-	-	1,515,600	1,515,600	442,050	439,778
565027	Transm Oper-Elec Tr-Demand	-	-	-	12,687,585	8,785,512	8,740,354
565030	Transm Oper-Elec Tr-OffSys	-	-	1,605,563	149,484	5,292	5,265
575700	Trans Op-Mkt Mon&Comp Ser-RTO	-	-	-	104,444	931,957	836,211
928003	Reg Comm Exp-FERC Assessment	-	-	-	239,669	335,565	344,807
	Total	12,117,025	22,674,472	19,909,632	22,344,431	14,210,417	17,228,411
L&P							
561400	Trans Op-Schd,Contr & Dis Serv	-	669,227	743,117	785,029	295,720	281,483
561800	Trans Op-Reli Plan&Std Dv-RTO	-	1,577	3,949	3,061	39,351	49,311
565000	Transm Oper-Elec Tr-By Others	4,174,803	4,231,449	-	30,164	(35,446)	(35,446)
565020	Trans of Electricity by Others	-	-	2,646,461	50,995	-	-
565021	Transm Oper-Elec Tr-Interunit	-	-	1,515,600	1,515,600	442,050	442,050
565027	Transm Oper-Elec Tr-Demand	-	-	-	2,941,279	2,313,040	319,924
565030	Transm Oper-Elec Tr-OffSys	-	-	26,970	7,135	-	-
575700	Trans Op-Mkt Mon&Comp Ser-RTO	-	-	-	-	286,699	241,564
928003	Reg Comm Exp-FERC Assessment	-	-	-	82,859	118,314	110,162
	Total	4,174,803	4,902,252	4,936,097	5,416,122	3,459,728	1,409,049

2010-14 GMO ENERGY RESOURCES						
		Dispatch - GWH				
Resources	**Fuel**	**2010**	**2011**	**2012**	**2013**	**2014**
Cooper PPA	Nuclear	630.73	577.11	578.84	630.69	53.57
Greenwood 1	Gas/Oil	5.03	8.62	10.30	11.56	14.24
Greenwood 2	Gas/Oil	4.32	7.72	9.68	10.78	13.63
Greenwood 3	Gas/Oil	3.79	6.89	8.98	9.64	12.62
Greenwood 4	Gas/Oil	3.15	5.96	6.99	7.43	11.70
Grey Co MPS	Wind	127.49	126.95	126.56	126.90	127.41
Grey Co SJLP	Wind	63.73	63.46	63.23	63.44	63.70
MPS Wind 2012	Wind	0.00	0.00	44.18	256.15	256.15
SJLP Wind 2012	Wind	0.00	0.00	22.09	128.08	128.08
Iatan 2 MPS	Coal	202.72	1,155.46	1,060.09	1,170.42	1,063.70
Iatan 1 St Joe	Coal	970.13	812.13	893.07	863.18	897.75
Jeffrey Ener 1	Coal	439.30	396.35	440.19	367.86	325.06
Jeffrey Ener 2	Coal	444.65	360.59	442.58	407.21	389.49
Jeffrey Ener 3	Coal	410.81	441.59	375.82	440.73	360.61
Kansas City Intl 1	Gas	0.00	0.00	0.00	0.00	0.00
Kansas City Intl 2	Gas	0.00	0.00	0.00	0.00	0.00
Lake Road 1	Gas/Oil	12.62	13.20	13.87	11.79	16.98
Lake Road 2	Coal/Gas/	14.94	17.18	16.41	13.98	21.73
Lake Road 3	Gas/Oil	0.40	0.85	0.96	0.97	1.90
Lake Road 4	Coal/Gas	527.46	421.77	400.36	416.36	447.97
Lake Road 5	Gas/Oil	24.37	24.87	26.60	21.14	31.54
Lake Road 6	Oil	0.06	0.17	0.16	0.25	0.36
Lake Road 7	Oil	0.03	0.08	0.07	0.10	0.14
Nevada	Oil	0.04	0.09	0.11	0.16	0.24
NPPD (Gentleman 1)	Coal	373.25	35.71	0.00	0.00	0.00
NPPD (Gentleman 2)	Coal	368.64	35.71	0.00	0.00	0.00
Ralph Green	Gas	4.01	7.15	7.84	8.24	11.15
Sibley 1	Coal	286.14	241.25	275.68	273.40	287.22
Sibley 2	Coal	284.13	235.79	272.89	263.63	284.75
Sibley 3	Coal	2,459.62	2,195.96	2,273.34	2,251.22	2,323.82
South Harper 3	Gas	18.35	31.05	34.86	35.10	43.54
South Harper 1	Gas	34.73	45.50	60.06	52.58	76.27
South Harper 2	Gas	26.59	40.71	46.34	41.70	57.71
XRoads 1	Gas	1.90	4.27	5.44	6.38	8.53
XRoads 2	Gas	1.91	4.19	5.54	5.96	8.28
XRoads 3	Gas	1.92	4.15	5.38	6.08	8.38
XRoads 4	Gas	1.95	4.12	5.50	6.23	8.00
MoPub Solar 2011	Solar	0.00	2.49	2.49	2.49	2.49
MoPub Solar 2014	Solar	0.00	0.00	0.00	0.00	4.04
SJLP Solar 2011	Solar	0.00	0.86	0.86	0.86	0.86
SJLP Solar 2014	Solar	0.00	0.00	0.00	0.00	1.30
DSM	DSM	35.64	82.71	127.87	179.96	230.60