Exhibit No.:	______________
Issue(s):	Fuel Adjustment Clause/ Crossroads
Witness/Type of Exhibit:	Mantle/Direct
Sponsoring Party:	Public Counsel
Case No.:	ER-2016-0156

DIRECT TESTIMONY

OF

LENA M. MANTLE

Submitted on Behalf of the Office of the Public Counsel

KCP&L GREATER MISSOURI OPERATIONS COMPANY

CASE NO. ER-2016-0156

** **

Denotes Highly Confidential Information that has been Redacted

July 15, 2016

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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service	)))))	File No. ER-2016-0156

AFFIDAVIT OF LENA MANTLE

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Lena Mantle, of lawful age and being first duly sworn, deposes and states:

1. My name is Lena Mantle. I am a Senior Analyst for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my direct testimony.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

Lena M. Mantle

Lena M. Mantle
Senior Analyst

Subscribed and sworn to me this 15th day of July 2016.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

JERENE A. BUCKMAN
My Commission Expires
August 23, 2017
Cole County
Commission #13754037

Jerene A. Buckman

Jerene A. Buckman
Notary Public

My Commission expires August 23, 2017.

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DIRECT TESTIMONY

OF

LENA M. MANTLE

KCP&L – GREATER MISSOURI OPERATIONS COMPANY

CASE NO. ER-2016-0156

INTRODUCTION

Q. Please state your name and business address.

A. My name is Lena M. Mantle and my business address is P.O. Box 2230, Jefferson City, Missouri 65102.

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

A. I am employed by the Missouri Office of the Public Counsel ("OPC") as a Senior Analyst.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the OPC.

Q. Please describe your experience and your qualifications.

A. I was employed by the OPC in my current position as Senior Analyst in August 2014. In this position, I have provided expert testimony in electric and water cases before the Commission on behalf of the OPC.

Prior to being employed by the OPC, I worked for the Staff of the Missouri Public Service Commission ("Staff") from August 1983 until I retired as Manager of the Energy Unit in December 2012. During the time I was employed at the

Missouri Public Service Commission ("Commission"), I worked as an Economist, Engineer, Engineering Supervisor and Manager of the Energy Unit.

Attached as Schedule LM-D-1 is a brief summary of my experience with OPC and Staff and a list of the Commission cases in which I filed testimony, Commission rulemakings in which I participated, and Commission reports in rate cases to which I contributed as Staff. I am a Registered Professional Engineer in the State of Missouri.

Q. What is the purpose of this testimony?

A. The purpose of this testimony is threefold:

1. Recommend approval of a modified fuel adjustment clause ("FAC") for KCP&L – Greater Missouri Operations Company ("GMO");

2. Recommend the Commission find GMO's Crossroads Generating Facility ("Crossroads") an imprudent resource for GMO and remove Crossroads from GMO's revenue requirement; and

3. Recommend the Commission allow $41.5 million in Missouri jurisdictional net rate base for capacity for GMO.

Q. Would you provide a summary of your background with respect to the FAC?

A. After the enactment of Section 386.266 RSMo establishing the FAC, Staff, OPC, representatives from the electric utilities, and other stakeholders worked together to draft proposed rules for the Commission's consideration to implement the statute. The draft rule development process included many stakeholder meetings where the participants developed proposed wording for draft rules. I attended and participated in all of the stakeholder meetings serving as Staff "scribe" at these stakeholder meetings and personally recorded the compromise language. I also participated drafting language regarding Staff's positions for the stakeholders' consideration in this process.

In June 2006, the Commission submitted proposed rules to the Secretary of State that were published in the July 17, 2006, Missouri Register. I attended, on behalf of the Staff, some of the public hearings the Commission held on its proposed rules in August and September of 2006.

In my employment with Staff and OPC, I have either filed testimony or participated in the determination of FAC positions in every general rate case where a Missouri investor-owned electric utility requested the establishment or modification of an FAC under the current statute. In addition, I have reviewed and, sometimes offered testimony, in every FAC rate change, prudence review, and true-up cases conducted in Missouri.

Drawing on my experience, I have written a white paper providing information on the history of the FAC in Missouri and a general description of the FAC as implemented in Missouri. This whitepaper is attached to this testimony and labeled Schedule LM-D-2.

Q. Would you provide a summary of your background with respect to GMO's Crossroads facility?

A. The genesis of any generation resource addition is the electric utility's resource planning process that determines prudent resource additions taking into account the forecasted needs of its customers and both cost and the risk associated with the resources. In my work at Staff, I participated in the development of the Commission's initial Chapter 22 Electric Utility Resource Planning rules that were first effective on May 6, 1993. I was involved in every Staff review of electric utility resource planning filings to meet the requirements of this rule from the effective date of the rules until the Commission issued a waiver for all of the investor-owned electric utilities from its resource planning rules in 1999 through 2005. During this period, the electric utilities were required to present updates of their resource plans in meetings with Staff and OPC every six (6) months. I attended all but one of these meetings during that period. Once the Commission's waiver ended in 2005, I participated in all of the electric utility resource plan reviews by Staff through the time I retired from Staff in December 2012. I also oversaw the revision of Chapter 22 that became effective June 30, 2011.

I have provided testimony before this Commission in eight cases with respect to GMO resource planning.[1] All eight of these testimony filings are relevant to the prudency of Crossroads.

[1] Case nos. ER-2012-0175, EO-2011-0390, ER-2010-0356, ER-2009-0009, ER-2007-0004, ER-2005-0436, and EF-2003-0465

FUEL ADJUSTMENT CLAUSE

Q. Is OPC recommending the Commission approve an FAC for GMO in this case?

A. Yes. OPC is recommending an FAC that will provide GMO with a reduction in risk regarding its recovery of its fuel and purchased power expenses while reducing the complexity of GMO's FAC, providing an incentive for GMO to prudently manage its fuel and purchased power costs and reducing the potential for errors.

Q. Would you outline the FAC that OPC is recommending for GMO?

A. OPC is recommending the Commission approve an FAC for GMO with the following features:

1. Only the following prudently incurred costs shall be included in GMO's FAC:
    a. Delivered fuel commodity costs including:
        i. Inventory adjustments to the commodities;
        ii. Adjustments to cost due to quality of the commodity; and
        iii. Taxes on fuel commodities;
    b. The cost of transporting the commodity to the generation plants; and
    c. The cost of power purchased to meet its native load.
2. These costs would be offset by:
    a. off-system sales revenues; and

b. Net insurance recoveries, subrogation recoveries and settlement proceeds related to costs and revenues included in the FAC.

3. An incentive mechanism that requires changes in GMO's fuel adjustment rates ("FARs") to account for 90% of the difference between the actual prudently incurred costs net of off-system sales and the net FAC costs included in its base rates. The other 10% would be absorbed or retained by GMO ("90/10 incentive mechanism").

OPC is not proposing any changes to the administration of the FAC, e.g. there would be no change in accumulation and recovery periods.

Q. What are the benefits of the FAC is OPC proposing?

A. These are the following benefits to OPC's recommended FAC:

1. The costs included are consistent with Section 386.266.1 RSMo;

2. It would increase the transparency of GMO's FAC by enabling the Commission, its Staff, GMO, and other interested parties to know exactly what is included in GMO's FAC;

3. Prudence audits would be simplified;

4. There would no longer be a need for a process for including a SPP cost or revenue that is similar to a cost already included in the FAC between rate cases since the FAC would not include Southwest Power Pool ("SPP") costs and revenues other than the cost of purchased power and off-system sales revenues;

5. Costs of fuel commodity and the transportation of that commodity and purchased power costs make up the majority of GMO's current FAC cost and OPC's recommendation includes all of the current FAC off-system sales revenue; and

6. The 90/10 incentive mechanism would actually provide an incentive for GMO to effectively manage fuel, purchased power and off-system sales as follows:

i. Fuel and purchased power costs net of off-system sales could increase by 20% and GMO would still recover more than 98% of these costs; and

ii. GMO would recover more than 100% of these costs when costs decline while also providing the customers benefits of declining fuel costs.

Q. Would you provide greater detail for each of these benefits?

A. Yes. The first benefit listed above is that the costs included in OPC's recommended FAC would be consistent with section 386.266.1 RSMo as follows:

> Subject to the requirements of this section, any electrical corporation may make an application to the commission to approve rate schedules authorizing an interim energy charge, or periodic rate adjustments outside of general rate proceedings to reflect increases and decreases in <u>its prudently incurred fuel and purchased power costs, including transportation</u>. The commission may, in accordance with existing law, include in such rate schedules features designed to provide the electrical corporation with incentives to improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities. (emphasis added.)

The costs OPC is proposing being included in GMO's FAC are the costs of the fuel used to generate electricity, the transportation of that fuel to the generating plant, and purchased power to meet GMO's native load.

In addition, the cost of purchased power would be included in the FAC. Purchased power would include the cost of power purchased above what is generated <u>to meet native load</u>. This would be restricted to the cost of energy from long-term bilateral contracts, energy and capacity charges from short-term (less than a year) bilateral contracts and power purchased on the SPP integrated market. No other SPP costs would be included in the FAC. Net insurance recoveries, subrogation recoveries and settlement proceeds related to costs and revenues would also be included in the FAC.

Q. How is OPC's recommendation consistent with Section 386.266.1?

A. Fuel commodity and the transportation of that commodity to GMO's generating facility is the purest definition of fuel and transportation costs. There can be no argument the drafters of the statute intended these costs be included in an FAC. The statute does not mention fuel adders, contractor costs, spinning reserve costs, startup costs, hedging costs, and a myriad of other costs and revenues that GMO is requesting be included in its FAC.

Purchased power to meet native load, either through bilateral contracts or on the SPP market also clearly meets the statute's intent. However, the inclusion of transmission costs for purchased power requires a belief that "transportation" and "transmission" are the same. Transmission is not a new phenomenon. Bilateral contracts required transmission at the time Section 386.266.1 RSMo was drafted. There were transmission costs associated with purchased power long before SPP became a regional transmission organization ("RTO"). When entering into a bilateral contract for purchased power, a prudent decision included an evaluation of the cost of transmission, if the cost of transmission cost was not already included in the contract, and the risk of changing transmission costs.

Had the drafters of the legislation intended for transmission to be included in periodic rate adjustments between rate cases, they would have included transmission in the statute. Instead they choose the word "transportation." Therefore, it is OPC's recommendation that no transmission costs be include in GMO's FAC.

Q. The statute is silent with regards to off-system sales revenue. Why is OPC recommending that the Commission include off-system sales revenue in GMO's FAC?

A. OPC is recommending the inclusion of off-system sales revenue because it is very difficult to accurately determine the fuel costs incurred to make off-system sales. If off-system sales are not included in the FAC, GMO would have to make a determination of the cost of fuel used to make that off-system sale and remove the fuel cost from the FAC. Not including off-system sales revenue in the FAC opens an avenue for mistakes, could result in different positions regarding the appropriate fuel cost to allocate to off-system sales and would increase the potential for imprudence. Incorporating off-system sales revenue in the FAC minimizes the potential for errors, disagreements and the opportunity for imprudence.

Q. Why should net insurance recoveries, subrogation recoveries and settlement proceeds related to costs and revenues be included in GMO's FAC?

A. These costs and revenues should be included consistent with the Commission's determination in the Kansas City Power & Light Company ("KCPL") rate case ER-2014-0370 where it found on page 39 of its *Report and Order*:

> Insurance recoveries, subrogation recoveries and settlement proceeds related to costs and revenues included in the FAC are revenues typically related to an unexpected incident or accident. If these types of revenues do occur, it is likely that at some point in time, prior to the receipt of the recovery or settlement, there were increased costs or reduced revenues due to that circumstance that have been include in the fuel adjustment rates paid by customers.

Q. Is GMO requesting costs that are not "fuel and purchased power costs, including transportation" in its FAC?

A. Yes, it is. It is easy to determine some proposed costs to be included in its FAC are not "fuel and purchased power costs, including transportation." For example, GMO is requesting that Federal Energy Regulatory Commission ("FERC") fees and SPP Schedule 1a and 12 be included in its FAC despite the Commission order in the recent KCPL rate case, ER-2014-0370, where the Commission found these fees were not linked to fuel and purchased power and should not be included in KCPL's FAC.[2]

Given the limited information provided by GMO, it is almost impossible to determine if the costs GMO is requesting be included in its FAC are actually "fuel and purchased power costs including transportation". This leads to the second benefit of OPC's FAC recommendation listed above: the Commission, Staff, GMO, and other interested parties will know exactly what is included in GMO's FAC in contrast to the lack of transparency in GMO's current FAC.

Q. The Commission's FAC rule 4 CSR 240-3.161(3)(H)[3] requires GMO to provide a complete explanation of the costs that it is recommending be included in its FAC. Do the explanations provided by GMO provide enough detail to determine if each cost GMO is requesting be included in its FAC is a "fuel and purchased power, including transportation" cost?

A. No. GMO provided its attempt to meet this filing requirement in Schedule TMR-1 attached to the direct testimony of Tim M. Rush. The list of general ledger accounts/resource codes and the "complete explanation" provided by GMO in Schedule TMR-1 is attached to this testimony as Schedule LM-D-3. A quick glance at this schedule reveals GMO provided very limited information in its direct filing regarding what exactly is in the FAC proposed by GMO. While some of the costs

[2] Report and Order, page 36, issued September 2, 2015
[3] The failure to mention an FAC filing requirement does not mean it is the position of OPC that the filing requirement was met.

may seem understandable, a closer examination of the costs raises several questions. For example, why are there so many resource codes for "NL Gas Costs & Transportation (Variable)"? What is "Contra-Steam Coal, Gas, Oil"? What is "Trans OP MKT MON&COMP SER RTO" and why should it be considered a fuel or purchased power cost?

Q. Given the limited explanations in Schedule TMR-1, is GMO requesting the inclusion of some costs that are not fuel and purchased power, including transportation in its request for an FAC?

A. Yes. The list includes costs for coal freeze and dust treatment, residuals, additives, emission allowances, and renewable energy credits revenues. None of these are fuel, purchased power or transportation costs.

Q. Did GMO provide any other detail regarding the costs and revenues that it is requesting be included in its FAC in its direct filing?

A. Yes. Additional detail can be found in the exemplar tariff sheets provided as Scheduled TMR-4 in Mr. Rush's testimony.

Q. Is the information provided in the exemplar tariff sheets consistent with the list of costs and revenues that Mr. Rush provided in Schedule TMR-1?

A. No, it is not. This became evident in GMO's response to OPC's data request 8001. This DR requested a detailed explanation of the costs listed in Schedule TMR-1. GMO went to its exemplar tariff sheets answer this DR requesting additional information and realized that there were inconsistencies between the exemplar sheets attached as TMR-4 and the list of costs included in Schedule TMR-1.[4]

Q. What conclusion can be made from this?

A. The number and types of costs and revenues in GMO's proposed FAC make the FAC unnecessarily complicated and impossible for the Commission, the other parties, and even GMO witnesses to know what GMO is proposing to be included in its FAC.

It also leads to questions regarding what costs and revenues are currently in GMO's FAC and whether or not the Commission actually approved all of the costs and revenues that are currently in GMO's FAC.

Q. Did GMO's response to OPC DR 8001 provide any additional clarification?

A. No. If anything it increased the uncertainty regarding what GMO is requesting be included in its FAC.

Q. Did GMO's response to any additional DRs reduce any of this uncertainty regarding what costs GMO was requesting to be in the FAC?

A. No. Additional DR responses from GMO showed Mr. Rush offered insufficient descriptions of the costs included in the general ledger account. For example, in his Schedule TMR-1, Mr. Rush described general ledger account 501420 as "NL Residual Costs." OPC DR 8027 requested a complete explanation of the costs

[4] In its response to OPC DR 8001, GMO stated that it would update the tariff sheets to include these costs.

included in 501420. A partial list of costs included in 5014200 provided by GMO in response to DR 8027 is shown below:

Labor Straight Time Union
Labor Overtime Union
Cost of Material Inventory
Contractors Equip Rental
Contractors Labor
Contractors Materials
Meal Allowance Bargaining Unit
PRLD Compensated Absences
Material Loads

Q. Do you consider these types of costs fuel and purchased power, including transportation costs?

A. No. These definitely are not fuel and purchased power, including transportation costs. However, this determination cannot be made with only the explanation of "NL Residual Costs" Mr. Rush provided as a complete explanation for the Commission's FAC minimum filing requirements.

Q. Did the additional DR responses provide any additional information regarding the costs that GMO is proposing be included in its FAC?

A. In addition to showing the "complete descriptions" provided in response to the FAC minimum filing requirements were inadequate, additional DR responses showed GMO is requesting costs included in its FAC even through it had not incurred costs in the general ledger accounts/resource codes in the last three years. DR responses also reveal there were costs included in the exemplar tariff sheets GMO does not currently incur.

Q. OPC's review discovered GMO was not incurring some costs that it was requesting be included in the FAC and had not incurred some of the costs that it was asking to be included. Did OPC make any other discoveries in examining the costs that GMO was requesting be included in its FAC?

A. Yes. OPC discovered that GMO "reclassified" some of the costs from FERC account 502, which is not currently included in GMO's FAC, to FERC account 501450, beginning in January 2016 and then, in this case, included this account in its list of costs it was proposing to be included in its FAC. GMO's direct filing did not explain that these costs, not previously included in its FAC, were being moved to an account that GMO is requesting be included in its FAC despite the Commission rule requirement, 4 CSR 240-3.161(3)(O), that the electric utility provide a description of how the costs included in the proposed FAC differ from the filing in the last general rate case.

Q. Would these costs that GMO reclassified be included in OPC's recommended FAC?

A. No. According to GMO's response to OPC DR 8027, the costs included in this account are the same type of costs listed above for Account 501420. These costs, like the costs in 501420, are not fuel and purchased power costs including transportation and therefore would not be included in the FAC proposed by GMO.

Q. Would OPC's recommended FAC prevent this from occurring in the future?

A. While there is no way to keep a utility from reclassifying costs, this type of reclassification would be more noticeable if there are fewer costs and revenues in the FAC and if those costs and revenues are well defined.

OPC witness Charles Hyneman will address GMO reclassifying this cost further in his rebuttal testimony in this case.

Q. Have there been different interpretations regarding the costs and revenues included in GMO's FAC in the past?

A. Yes. GMO's first true-up case, EO-2009-0341, revealed a misunderstanding between Staff and GMO regarding how off-system sales were to be treated in GMO's FAC. Staff and GMO came to an agreement in this case to exclude off-system sales from GMO's FAC because the FAC tariff sheets did not explicitly state off-system sales revenues were included in GMO's FAC.

Another difference of opinion regarding what was actually included in GMO's FAC came to light in Staff's third prudence audit of GMO's FAC in case EO-2011-0390 when Staff and GMO disagreed regarding the inclusion of purchased power hedging costs.

Q. What conclusions can you draw on this issue based on your review of the direct filing FAC minimum filing requirements as well as GMO responses to Staff and OPC issued DRs?

A. The limited definitions provided by GMO in its direct filing are not "complete explanations" as required by Commission rule and cannot be relied on for a complete understanding of the costs and revenues GMO is requesting be included. While a more complete list can be found in the exemplar tariff sheets, any list compiled from the exemplar tariff sheets is also inaccurate. The large number of costs and revenues GMO is requesting be included in its FAC along with the incomplete explanations are likely to result in non-fuel and purchased power costs being included in the FAC and in further disagreements regarding exactly what costs are included in GMO's FAC.

Q. Would OPC's recommended FAC resolve these issues?

A. OPC's recommendation to limit the costs and revenues in the FAC should resolve many of these issues.

Q. The next benefit you list is a simplification of prudency reviews. Would you please explain?

A. Limiting the types of costs and revenues included in GMO's FAC would greatly reduce the number of costs and revenues that would need to be reviewed in a prudency audit. Auditors would no longer have to review a myriad of types of costs such as SPP costs, emission costs, hedging policies and costs, and transmission costs. Instead of attempting to audit dozens of vaguely described non-fuel and purchased power expenses, auditors could concentrate on the cost of the fuel commodity, the cost to transport that commodity to the generation plant, purchased power and off-system sales - actual costs contemplated by statute and regulation.

For GMO's FAC, Mr. Rush listed fifty-three (53) different cost and seven (7) different revenue general ledger accounts/resource codes. As previously described in this testimony each of these general ledger accounts/resource codes may have multiple cost types recorded in the account. The limited number of costs and revenues proposed by OPC would greatly reduce the number and types of costs and revenue reviewed for prudence.

Q. In its prudence audits does Staff review each of the types of costs and revenues that GMO includes in its FAC?

A. It seems that it does not. The Table of Contents[5] from the report filed for the last GMO FAC audit performed by Staff is attached to this testimony as Schedule LM-D-4. This Table of Contents shows Staff did review the large cost items – fuel commodity and transportation of that commodity and generation utilization. Staff also reviewed purchased power and off-system sales. However, Staff's FAC audit report did not include a description the many SPP costs included in GMO's FAC and there is no discussion regarding a review of the fuel additive accounts.

Q. Would you comment on the effectiveness of FAC prudence audits?

[5] Case no. EO-2016-0053, *Prudence Review of Costs Related to the Fuel Adjustment Clause for the Electric Operations of KCP&L Greater Missouri Operations Company*, filed February 29, 2016.

A. Theoretically, FAC prudence audits would identify all instances where an imprudent action by an electric utility resulted in harm to the customers with respect to each of the costs and revenues in an FAC. In practice, prudence audits are limited in scope due to resource constraints and only identify imprudence if the auditor asks the right questions or stumbles on imprudence.

Q. Is there an example of a Staff prudence audit of GMO's FAC that did not find a multi-million dollar flow through of costs that should not have been collected from GMO's customers in its FAC?

A. Yes. In the last Staff GMO FAC audit identified above, the Commission's Energy Resources Staff analyzed a variety of items in examining whether GMO prudently incurred the fuel and purchased power costs associated with GMO's FAC for the period of December 1, 2013 through May 31, 2015. One of the items Staff reviewed was transmission costs. GMO's FAC, in compliance with Commission order in case no. ER-2012-0175, was to only allow transmission costs necessary to receive purchased power to serve native load and make off-system sales. No transmission costs associated with Crossroads was to be included in base rates or in the FAC. Staff reported it found no indication GMO's transmission costs were imprudent during the review period.[6] The Commission found Staff's report and recommendation to be reasonable and approved Staff's report.[7]

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[6] *Prudence Review of Costs Related to the Fuel Adjustment Clause for the Electric Operations of KCP&L Greater Missouri Operations Company*, page 23.
[7] *Order approving Staff's Prudence Review*, effective April 15, 2016

In its FAC true-up case filed on July 1, 2016, in case no. ER-2017-0002, GMO notified the Commission that it was including in its true-up amount a correction of $4.6 million of transmission costs associated with Crossroads that it had flowed through its FAC. This came to light when GMO began doing research to answer data requests issued by Staff's Auditing Department in this rate case. This is an error that was not caught in Staff's prudence audit that the Commission had approved.

Q. Should Staff's prudence audit have caught this error?

A. Yes, it should have. However, errors like this are likely to happen given the complexity of GMO's FAC, the lack of transparency regarding what is included in GMO's FAC, Staff resource constraints, and the fact that Staff has to know the right questions to ask to get the right information from GMO. This discovery of incorrect costs flowing through the FAC came only after Staff's Auditing Department submitted several probing data requests in this case, not in an FAC prudence review.

Q. Is this the first time GMO corrected an error that it made in the amount it included in its FAC?

A. No, it is not. In case no. ER-2014-0204, GMO's filing to change its FAR for accumulation period 13 ending November 30, 2013, GMO reduced its FAC for its MPS customers by $1.5 million because it had discovered, during its research to develop testimony in a GMO steam case, it had erroneously included fuel hedge positions in its FAC that were actually steam costs.

Q. How would OPC's FAC recommendation reduce the likelihood of this happening?

A. While not guaranteeing this would not happen again, the FAC recommended by OPC would reduce the number and types of costs and revenues included in GMO's FAC, thus reducing the likelihood that such errors would occur again.

Q. The next benefit listed is that no SPP costs and revenues other than the cost of purchased power and off-system sales revenues would be included. Why should SPP costs and revenues be removed from the FAC?

A. Simply because SPP costs and revenues other than spot market purchased power costs and off-system sales revenues are not fuel or purchased power costs. They are the costs incurred and revenues received in doing business through an RTO and in the RTO market. Section 386.266 RSMo requires costs that are included in the FAC be limited to fuel and purchased power costs, including transportation. Many of the SPP charges that GMO is requesting be included in its FAC were not even envisioned when the law was drafted.

Q. What is the impact of removing SPP costs and revenues from GMO's FAC?

A. It would greatly simplify the FAC. The exemplar FAC tariff sheets provided as Schedule TMR-4 include two pages that list 64 different SPP charge/revenue types that GMO would be able to flow through its FAC.[8] A comprehensive prudence

[8] These SPP charge and revenue types are not included in GMO's attempt to meet the Commission's FAC minimum filing requirements of complete explanations of all costs and revenues that GMO is requesting be included in its FAC.

review should include carefully looking at each of these 64 charge and revenue types for imprudence and to avoid the type of errors GMO has had to file to correct in its FAC. Prudence reviews could be more comprehensive since the number of costs and revenues to be reviewed would be greatly reduced.

In addition, there would no longer be a need for a process to include new SPP charges and revenues that are "like" SPP costs and revenues already included in the FAC.[9]

Q. Would OPC's recommendation increase the risk that GMO faces with respect to FAC costs?

A. Yes, but only with respect to the non-fuel and purchased power costs now included in GMO's FAC. However, because a large majority of the costs in the current FAC are fuel commodity, the transportation of that commodity, and purchased-power costs, the increase in risk is slight. OPC's recommendation would still result in GMO recovering increases in true fuel and purchased power costs thus reducing the risk to GMO of increases in fuel and purchased power costs consistent with Section 386.266 RSMo.

Q. Would removal of costs from the FAC result in GMO not recovering the non-fuel and purchased power costs now included in its FAC?

[9] This process is detailed beginning at the bottom of exemplar tariff sheet 127.5 and continues through all of sheet 127.6

A. No, it would not. These costs would still be included in the revenue requirement for GMO. Not including these costs in the FAC would restore the traditional ratemaking incentives to GMO in regards to these costs. If GMO can find efficiencies that could reduce these costs, then shareholders would see a benefit. Including these costs in the FAC removes GMO's incentive to take actions to decrease these non-fuel and purchased power costs.

Likewise, removal of revenue types from the FAC would not result in ratepayers not receiving the benefits from these revenue sources. Normalized revenues from these sources would still be included in determining the revenue requirement. If GMO can find efficiencies that could increase these revenues, then shareholders would see a benefit. Including non-fuel and purchased power revenues in an FAC creates apathy regarding increasing these revenues because GMO sees very little benefit to increasing revenues.

Q. How would changing the incentive mechanism to 90/10 affect GMO's cost recovery when fuel costs are increasing?

A. It depends on how accurate the FAC costs and revenues put into base rates are and how much the costs increase. If the base is accurate and costs increase 10%, then GMO will recover 99.1% of its actual fuel costs. If the costs increase 20%, then GMO will still collect 98.3% of its fuel costs. While the 1.7% of fuel and purchased power cost may be millions of dollars that GMO would not recover, it is considerably less than the millions of dollars GMO would not recover without an FAC.

Q. How would changing the incentive mechanism to 90/10 affect GMO's cost recovery when fuel costs are decreasing?

A. Again, it depends on how accurate the FAC costs and revenues put into base rates are and how much the costs decrease. If the base is accurate and costs decrease 10%, then GMO will recover 101.1% of its actual fuel costs. If the costs decrease 20%, then GMO will collect 102.5% of its actual fuel costs.

Q. How does that compare to what GMO would recover with a 95/5 incentive mechanism?

A. The table below summarizes the difference in the percent of costs GMO would recover with the 90/10 and 95/5 sharing mechanisms.

Comparison of
Percent of FAC Costs Recovered

Actual Costs as percent of Base Fuel Costs	Incentive Mechanism	
	90/10	95/5
120%	98.3%	99.2%
110%	99.1%	99.5%
100%	100%	100%
90%	101.1%	100.6%
80%	102.5%	101.3%

Q. Would you summarize this table?

A. With the current incentive mechanism, GMO recovers essentially all of its FAC costs even if fuel costs increase 20%. A 95/5 sharing mechanism provides little to no incentive for GMO to take any actions to keep the FAC costs within 20% of what is included in base rates. A 90/10 sharing mechanism actually results in an impact, albeit small, on cost recovery when FAC costs increase. It also provides more of an incentive to GMO to decrease its FAC costs.

Q. Would you summarize the benefits of the FAC proposed by OPC?

A. The FAC proposed by OPC would result in the recovery of 90% of the actual cost of its fuel commodity (including the transportation of the commodity), and purchased power, net of off-system sales, above what is included in base rates. It maintains consistency with the state law granting Commission the authority to allow an FAC. It limits the costs and revenues included in the FAC increasing the transparency of what is included in the FAC. It reduces the likelihood of errors and increases the ability to conduct a comprehensive prudence review. Lastly, it offers a more meaningful incentive for GMO to manage, to the extent it is able, the fuel and purchased power costs and off-system sales revenues.

CROSSROADS GENERATING FACILITY

Q. What is OPC's recommendation regarding Crossroads?

A. OPC recommends the Commission find GMO's Crossroads Generating Facility ("Crossroads") an imprudent resource for GMO. The inclusion of the capital costs and expenses related to Crossroads is imprudent due to actions by GMO's predecessor Aquila, Inc. ("Aquila"), GMO's parent holding company Great Plains Energy ("GPE"), and GMO.

Q. Would you briefly describe Crossroads?

A. Crossroads consists of four 75 megawatt ("MW") General Electric 7EA combustion turbines located over 500 miles from GMO's service territory in Clarksdale, Mississippi. It was built in 2002 by a non-regulated subsidiary of Aquila titled Aquila Merchant Services. It is owned by the City of Clarksdale for property tax abatement purposes. A tolling agreement for the capacity and energy of the plant was originally held Aquila Merchant Services, which assigned the agreement to Aquila. The agreement runs through 2032 with a right to extend up to ten more years. Crossroads is controlled by GMO but operated by the City of Clarksdale. The plant is recorded as a capital lease on the books and records of GMO and is currently assigned to GMO's MPS customers.

GMO's direct filing in this case shows it expects **

**. Schedule BLC-5 HC provided in the direct testimony of GMO witness Burton L. Crawford, provides GMO's expected dispatch of GMO's units over the next four years. This schedule shows that GMO expects to generate **

**.

To be considered as capacity, GMO has to pay for firm transmission from Crossroads to its service territory for the entire year, even though it is rarely utilized, and then only in the peak summer months. Because it is located in the Midcontinent Independent System Operator ("MISO"), a different RTO than GMO belongs to, GMO must not only pay the firm point-to-point transmission costs that it originally contracted for to transmit energy to GMO's service territory, but also additional MISO costs.

Q. What is the prudence standard that OPC is using?

A. OPC is using the prudence standard upheld by the Court of Appeals in *State ex rel. Associated Natural Gas Co. v. Public Service Com'n of State of Mo.* This court decision stated:

> [A] utility's costs are presumed to be prudently incurred.... However, the presumption does not survive "a showing of inefficiency or improvidence... [W]here some other participant in the proceeding creates a serious doubt as to the prudence of expenditure, then the applicant has the burden of dispelling these doubts and proving the questioned expenditure to have been prudent.
>
> In the same case, the PSC noted that this test of prudence should not be based upon hindsight, but upon a reasonableness standard: [T]he company's conduct should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problem prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the tasks that confronted the company.[10]

[10] 954 S.W.2d 520, 528-29 (Mo. App. W.D., 1997) (citations omitted)

As a part of that decision, the Court of Appeals held that to disallow costs based on imprudence, the Commission must determine the detrimental impact of that imprudence on the utility's ratepayers.[11] This is the same prudence standard used by Staff in its FAC prudence reviews.[12]

Q. Is this the first time the prudence of resources to meet GMO's customer's needs has been brought before the Commission?

A. No. It is not. Staff filed testimony regarding the imprudence of using Purchased Power Agreements ("PPAs") instead of building generation in case nos. ER-2005-0436, ER-2007-0004, and ER-2009-0090. Staff also provided testimony regarding the imprudence of GMO including Crossroads in case nos. ER-2010-0356 and ER-2012-0175.

Q. Has GMO dispelled the doubts of imprudence regarding Crossroads in this case?

A. No. It has not. It has provided testimony in this case that Crossroads is the least-cost alternative for GMO's customers in 2015. However, this is irrelevant. GMO's customers should not have to bear increased costs in 2016 and beyond due imprudent decisions made by GMO and its predecessor prior to this case.

Q. Why would including Crossroads costs in this case be imprudent?

[11] *Id.* at 529-30.
[12] Case no. EO-2016-0053, *Prudence Review of Costs Related to the Fuel Adjustment Clause for the Electric Operations of KCP&L Greater Missouri Operations Company, Staff Report*, page 4.

A. While I have no reason to believe Crossroads operates inefficiently, it is imprudent to require GMO's customers to pay more due to imprudent resource decisions in 2003 affects the cost of provision of energy for 30 to 40 years thus impacting the bills of customers for decades.

Crossroads is imprudent because its location, of more than 500 miles from GMO's service territory and outside of GMO's RTO, results in high transmission costs to provide capacity and energy to GMO's customers. By asking for Crossroads costs to be included in this case, GMO is asking its customers to assume a contract with the city of Clarksdale, Mississippi for Crossroads through the year 2032 - a contract that no other entity was willing to take the risk of at a price well below book value in 2001 and 2005.

Aquila acted imprudently when it did not build regulated generation and instead relied on short-term PPAs. GPE acted imprudently when it transferred to GMO a resource located 500 miles from its service territory that no one else would buy and requested cost recovery at book value from GMO's customers.

To truly understand why Crossroads is imprudent, it is important to understand the history of resource planning decisions by GMO and its predecessor Aquila. The prudency of including of Crossroads costs in rates should not be viewed in the isolation of this case and this point in time.

Q. Would you summarize this history?

A. In the 1990's, FERC began restructuring the national wholesale electricity market. Prior to FERC's wholesale market restructuring, electric utilities with excess capacity and generation sold excess capacity and energy through long-term (10 to 20 year) bilateral contracts at cost plus a small margin. The restructuring promoted by FERC gave electric utilities with excess energy the opportunity to sell energy, if transmission was available, at much higher margin than what had previously been received through long-term bilateral contracts. Electric utilities became reluctant to enter into long-term, low cost-plus purchased power contracts as they had previously. Instead companies with excess generation hoped to make a larger margin through short-term wholesale energy sales.

FERC also opened the wholesale electricity market to Independent Power Producers ("IPP") – entities which are not public utilities, but which own facilities to generate electric power for sale on the wholesale market.

At the same time, the energy market in states with restructuring offered IPPs an opportunity to make a greater return than the electric utilities could earn in states with vertically integrated electric utilities. IPPs began building generation they believed would result in a profitable return based on the status of electric restructuring in the state, demand for electricity, and transmission constraints. But the potential increase in earnings came with an increase in risk. IPPs were not always guaranteed a buyer for their energy. They did not have a "captive" customer base and were not guaranteed a price or a consistent earnings stream.

IPPs typically built combustion turbine generators because, compared to other different types of generation, they are inexpensive to build and can be built in a relative short time period (less than two years.) IPP-built generation took the risk that there would be demand for their generation and that it would be at a price which would result in a profit.

Between 2000 and 2005 Aquila began purchasing utilities in other states where the electric utility industry was restructuring. It also bought electric and gas utilities in other countries. It began building a fleet of merchant plant generation as IPPs in different parts of the nation where it believed, due to electric restructuring and transmission constraints, it could earn a high return on its investments. This fleet of merchant plants included the Raccoon Creek and Goose Creek generation facilities in Illinois, now owned by Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri"), and Crossroads in Mississippi. Aquila Merchant also bought three combustion turbines that it stored while waiting to determine where these turbines could be placed to make the most profit for Aquila.

Q. What was happening with respect to Aquila's Missouri regulated utility during this time?

A. Aquila's resource planning process in the 1990's showed its Missouri regulated electric utility would need additional capacity and energy in 2000. In this planning process, a combined-cycle generation plant (built in Aquila's Missouri service territory) was determined to be the preferred resource to meet Aquila's customers' current and long-term needs. Consistent with its corporate direction, Aquila Merchant and Calpine built the Aries combined-cycle plant[13] shown to be the preferred resource in Aquila's resource plan as an IPP. Aquila entered into a five-year purchased power agreement for 500 MW of capacity and energy from the Aries plant ("Aries PPA") to meet its Aquila Missouri customers' needs.

Q. Was the Aries PPA a good fit for GMO's portfolio in 2000?

A. Only in the short-term. Aquila still needed additional capacity when the Aries PPA ended in June 2005. Because Aries was an IPP, it was not a generation resource Aquila Missouri could count on for capacity and energy past May 31, 2005. If it had been built and owned by the regulated Aquila entity, it would have been available for the life of the plant and the Commission would not be facing the issue of imprudence in this case.

Q. Was building Aries as an IPP an imprudent decision by Aquila?

A. While in hindsight it seems to have been imprudent for Aquila to build the Aries plant as an IPP, given the changing electric utility environment at the time the decision was made to build the Aries plant, the conduct was reasonable considering Aquila had to solve its problem prospectively. Aquila foresaw a restructured electric industry in Missouri much like what was occurring in other states and the Missouri Legislature was considering restructuring the electric industry in Missouri. Aquila was acting to reduce its potential stranded

[13] Now know as the Dogwood Plant

investment if Missouri did decide to restructure. Thus, even though GMO customers today would have benefited from Aquila Missouri's regulated division building Aries instead of Aquila Merchant, not owning the Aries plant does not meet the standard of imprudence.

Q. How is this tied to Crossroads?

A. All of the capital expenditures for other utilities and IPP generation spread corporate Aquila thin financially and exposed it, including its regulated business in Missouri, to higher risk. Then the Enron scandal unfurled, and interest in the Missouri Legislature to restructure the electric industry in this state waned.

The collapse of Enron and uncertainty in the electric industry had a significant impact on Aquila's financial condition. When Aquila needed to replace the Aries PPA of 500 MW of capacity and energy, Aquila Merchant was selling much of its merchant fleet, including its share of the Aries plant, at a loss.

Q. How did Aquila choose to meet its 500 MW need in 2005?

A. When it became apparent the electric industry was not going to be restructured in Missouri, Aquila realized it would need to acquire additional capacity to meet the requirements of its Missouri vertically integrated utility in 2005. It began reviewing the optimal resources available to meet its capacity and energy requirements in 2001 and then, because of dramatic drops in the costs of capacity, again in 2003. Aquila's resource planning process in 2003 showed that the least cost and most risk adverse resource plan was to build five combustion turbines in its service territory to meet its needs. However, Aquila chose instead to purchase the three 105 MW combustion turbines that Aquila Merchant had in storage and place them on the South Harper site in its service territory near Peculiar, Missouri.[14] To meet the rest of its customers' needs Aquila decided to rely on purchased power agreements.

Q. You stated earlier the electric industry was moving away from long-term purchased power agreements. Was Aquila able to enter into any long-term purchased power agreements?

A. Yes. It entered into an agreement with Nebraska Public Power District for 75 MW of base load capacity and energy for nine years beginning in December 2004. However, Aquila still needed additional capacity and energy.

Q. How did it Aquila meet its additional needs?

A. Aquila was only able to enter into short-term year-to-year contracts. In 2005 and 2007 these contracts were with its Crossroads merchant plant[15] for the summer months and had a fixed capacity price with the price of any energy produced for Aquila based on the spot market price of natural gas.

Q. Why was Crossroads available for these short-term PPAs?

A. Even though Aquila Merchant was actively looking to sell Crossroads during this time period, there were no buyers for this generation plant. According to Exhibit

[14] Litigation regarding the South Harper plant also contributed to uncertainty in Aquila's resources from 2005 until it was determined to be useful and used for service by the Commission in March 2009.
[15] Crossroads became operational in October 2002.

395 HC in GMO rate case no. ER-2012-0175[16] **

**

Q. What is the above quote referring to when it states ** **?

A. It was Aquila's expectation that, if it placed power plants in places with transmission constraints, it would receive a higher price for the energy that its generation would provide resulting in greater earnings. Transmission constraints, which Aquila believed was a positive when it wanted to make money generating electricity, turned to a negative when Aquila sought to sell Crossroads.

In addition, due to transmission constraints, Crossroads has a Special Protection System. Crossroads is served by two transmission lines. However, only one of the transmission lines can handle Crossroads at full capacity. If that line goes out of service, the other line can only handle three of the four turbines at full load. This results in a Special Protection System which requires to ramp down one of the turbines should the second line become overloaded.

Q. Were the decisions made by Aquila to enter into PPA's imprudent at the time?

[16] Case No. ER-2012-0175, EFIS item 462, Exhibit 395 HC,** **

A. Yes, they were. The decisions were short-sighted. Staff repeatedly informed Aquila that PPA's were not an optimal solution to meet its customer's needs. It had become clear that Missouri was no longer interested in restructuring its electric industry removing the concern of stranded capital investments. Other regulated electric utilities in Missouri were adding generation at that time.

Q. Did Aquila's decision to meet its generation needs through PPAs result in detriment to its customers?

A. Yes, it did. The harm to customers was not monetary due to settlements Aquila reached with other parties in rate cases. The harm was an increase in the risk of future costs - generation availability and transmission costs. If Aquila had built in its territory instead of relying on PPAs, GMO's customers would have certainty of steel in the ground available for at least 40 years. In addition, there would be no additional costs due for transmission.

Q. To this point in your testimony you have described the imprudent actions of Aquila. What occurred regarding meeting the resource needs of Aquila's regulated electric utility when GPE purchased Aquila?

A. GPE entered into an agreement to acquire Aquila's Missouri regulated utility and Crossroads, which was still owned by Aquila Merchant, in February 2007. Following the acquisition closing on July 14, 2008, GPE became the owner of Aquila and renamed it GMO. GPE's acquisition included not only Aquila's

Missouri regulated electric utility division but also the agreement with Crossroads that Aquila Merchant had tried to sell.

Q. Once GPE acquired Aquila did it change how the load requirements of GMO's customers were met?

A. Yes, it did. Soon after the acquisition closing, GPE transferred Crossroads to GMO to be considered a GMO generation resource. GPE originally transferred Crossroads to GMO at its net book value, not the market value Aquila had offered to others. GMO then asked its customers to pay not only the capital costs of Crossroads, but also the transmission costs associated with having a generation plant 500 miles away from its service territory.

Q. Did the acquisition of Aquila by GPE and the subsequent transfer of Crossroads to GMO change the disincentives regarding Crossroads?

A. No. Transmission is still an issue as demonstrated by the increase in transmission costs GMO is requesting in this case. In addition, with the transfer of Crossroads to GMO, it is tied to the Crossroads contract with the City of Clarksdale through 2032.

Q. Did Staff provide notification to Aquila and GMO that it found their actions imprudent?

A. Yes, it did. Schedule LM-D-5 attached to this testimony is a reproduction of Schedule LMM-1 provided in Appendix 5 of the *Staff Report Revenue Requirement Cost of Service* filed in the GMO general rate increase case ER-2010-0356. This schedule provides an explanation of the history of Aquila's actions and Staff's response regarding resource additions for Aquila, and then GMO, since 2000 and through the filing date of the schedule on November 17, 2010. In GMO's next rate case, ER-2012-0175, GMO again asked for inclusion of Crossroads costs in its cost of service and Staff again provided testimony regarding the imprudence of including Crossroads as a GMO resource.

Q. Did GMO provide any additional information in this case that shows that the decision to move Crossroads from a non-regulated business unit to GMO was imprudent?

A. Yes. GMO has provided testimony that transmission service has increased by $6.7 million to $12.3 million in 2014.

Q. Is OPC's prudency recommendation based on hindsight?

A. No, it is not. Staff began informing Aquila it was acting imprudent as soon as Aquila first informed Staff and OPC it intended to not follow its least-cost, lowest-risk resource plan in 2003. If Aquila had built the Aries Plant as a regulated resource in the 1990's, this issue would not be before the Commission now. If Aquila had made a prudent decision to build additional capacity in its service territory in 2003, this issue would not be before the Commission in this case. In each case before the Commission with generation at issue since 2003, Staff has argued the resource decisions made by Aquila, and subsequently GMO, were imprudent.

In addition, the potential impact of increases in transmission costs for Crossroads filed in this case was a circumstance that should have been vetted by GMO. Crossroads was built in 2002 in Entergy territory more than 500 miles from the GMO service territory. When GPE acquired Crossroads, Entergy had not determined which, if any, RTO it would join. While GMO may have expected Entergy to join SPP, resulting in no change to transmission costs, GPE should have conducted a thorough analysis of the potential impact on transmission costs if Entergy joined a different RTO. The potential for Entergy to join MISO and the potential increase in transmission costs was a risk GMO should have considered.

Q. Has the decisions made by GMO with respect to Crossroads been detrimental to GMO's customers?

A. Without a determination of imprudence by this Commission, the decision by GPE to transfer a generation facility 500 miles from its service territory (that includes the baggage of a contract through 2032, transmission constraints, and high transmission costs) will result in detriment to GMO's customers. In this case, the detriment would be the increase in transmission costs that GMO is asking the Commission to include in its revenue requirement.

Q. What is OPC's recommendation to the Commission regarding Crossroads?

A. It is OPC's recommendation the Commission find the assumption of the Crossroads contract by GMO is imprudent and to not allow any capital costs or expenses related to Crossroads be included in GMO's revenue requirement.

ADDITIONAL CAPACITY

Q. What would the capacity impact of removing Crossroads from GMO capacity be?

A. Crossroads is currently included as capacity for GMO to meet the capacity margin requirements of the SPP. If GMO's capacity was reduced by the 300 MW of Crossroads, SPP would penalize GMO because of insufficient capacity margin.

Q. Is OPC recommending GMO no longer include Crossroads as its capacity to meet SPPs capacity margin requirement?

A. No. OPC is recommending the Commission find the costs of Crossroads imprudent. However, recognizing that additional capacity would be needed without Crossroads, OPC is recommending the Commission include $41.5 million in GMO's net rate base for capacity.

Q. Why is OPC recommending $41.5 million be included in net rate base for capacity?

A. This is OPC's estimate of the amount that would have been included in rate base had GMO made the prudent decision to build in generation in its service territory when the Aries PPA ended in June 2005. Because there would be no additional transmission costs had GMO built generation in its service territory, OPC is not recommending any transmission costs be included for this capacity.

Q. Does this conclude your direct testimony?

A. Yes.

Education and Work Experience Background for

Lena M. Mantle, P.E.

In my position as Senior Analyst for the Office of the Public Counsel ("OPC") I provide analytic and engineering support for the OPC in electric, gas, and water cases before the Commission. I have worked for the OPC since August, 2014.

I retired on December 31, 2012 from the Public Service Commission Staff as the Manager of the Energy Unit. As the Manager of the Energy Unit, I oversaw and coordinated the activities of five sections: Engineering Analysis, Electric and Gas Tariffs, Natural Gas Safety, Economic Analysis, and Energy Analysis sections. These sections were responsible for providing Staff positions before the Commission on all of the electric and gas cases filed at the Commission. This included reviews of fuel adjustment clause filings, resource planning compliance, gas safety reports, customer complaint reviews, territorial agreement reviews, electric safety incidents and the class cost-of-service and rate design for natural gas and electric utilities.

Prior to being the Manager of the Energy Unit, I was the Supervisor of the Engineering Analysis Section of the Energy Department from August, 2001 through June, 2005. In this position, I supervised engineers in a wide variety of engineering analysis including electric utility fuel and purchased power expense estimation for rate cases, generation plant construction audits, review of territorial agreements, and resolution of customer complaints all the while remaining the lead Staff conducting weather normalization in electric cases.

From the beginning of my employment with the Commission in the Research and Planning Department of the in August, 1983 through August, 2001, I worked in many areas of electric utility regulation. Initially I worked on electric utility class cost-of-service analysis, fuel modeling and what has since become known as demand-side management. As a member of the Research and Planning Department under the direct supervision of Dr. Michael Proctor, I participated in the development of a leading-edge methodology for weather normalizing hourly class energy for rate design cases. I took the lead in developing personal computer programming of this methodology and applying this methodology to weather-normalize electric usage in numerous electric rate cases. I was also a member of the team that assisted in the development of the Missouri Public Service Commission electronic filing and information system ("EFIS").

I received a Bachelor of Science Degree in Industrial Engineering from the University of Missouri, at Columbia, in May, 1983. I am a registered Professional Engineer in the State of Missouri.

Lists of the Missouri Public Service Commission rules in which I participated in the development of or revision to, the Missouri Public Service Commission Testimony Staff reports that I contributed to and the cases that I provided testimony in follow.

Missouri Public Service Commission Rules

4 CSR 240-3.130	Filing Requirements and Schedule of Fees for Applications for Approval of Electric Service Territorial Agreements and Petitions for Designation of Electric Service Areas
4 CSR 240-3.135	Filing Requirements and Schedule of Fees Applicable to Applications for Post-Annexation Assignment of Exclusive Service Territories and Determination of Compensation
4 CSR 240-3.161	Electric Utility Fuel and Purchased Power Cost Recovery Mechanisms Filing and Submission Requirements
4 CSR 240-3.162	Electric Utility Environmental Cost Recovery Mechanisms Filing and Submission Requirements
4 CSR 240-3.190	Reporting Requirements for Electric Utilities and Rural Electric Cooperatives
4 CSR 240-14	Utility Promotional Practices
4 CSR 240-18	Safety Standards
4 CSR 240-20.015	Affiliate Transactions
4 CSR 240-20.017	HVAC Services Affiliate Transactions
4 CSR 240-20.090	Electric Utility Fuel and Purchased Power Cost Recovery Mechanisms
4 CSR 240-20.091	Electric Utility Environmental Cost Recovery Mechanisms
4 CSR 240-22	Electric Utility Resource Planning
4 CSR 240-80.015	Affiliate Transactions
4 CSR 240-80.017	HVAC Services Affiliate Transactions

Office of Public Counsel Case Listing

Case	Filing Type	Issue
ER-2016-0023	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
WR-2015-0301	Direct, Rebuttal, Surrebuttal	Revenues, Environmental Cost Recovery Mechanism
ER-2014-0370	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
ER-2014-0351	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
ER-2014-0258	Direct, Rebuttal, Surrebuttal	Fuel Adjustment Clause
EC-2014-0224	Surrebuttal	Policy, Rate Design

Staff Direct Testimony Reports

ER-2012-0175	Capacity Allocation, Capacity Planning
ER-2012-0166	Fuel Adjustment Clause
ER-2011-0028	Fuel Adjustment Clause
ER-2010-0356	Resource Planning Issues
ER-2010-0036	Environmental Cost Recovery Mechanism
HR-2009-0092	Fuel Adjustment Rider
ER-2009-0090	Fuel Adjustment Clause, Capacity Requirements
ER-2008-0318	Fuel Adjustment Clause
ER-2008-0093	Fuel Adjustment Clause, Experimental Low-Income Program
ER-2007-0291	DSM Cost Recovery

Missouri Public Service Commission Staff Testimony

Case No.	Filing Type	Issue
ER-2012-0175	Rebuttal, Surrebuttal	Resource Planning Capacity Allocation
ER-2012-0166	Rebuttal, Surrebuttal	Fuel Adjustment Clause
EO-2012-0074	Direct/Rebuttal	Fuel Adjustment Clause Prudence
EO-2011-0390	Rebuttal	Resource Planning Fuel Adjustment Clause
ER-2011-0028	Rebuttal, Surrebuttal	Fuel Adjustment Clause
EU-2012-0027	Rebuttal, Surrebuttal	Fuel Adjustment Clause
ER-2010-0356	Rebuttal, Surrebuttal	Resource Planning Allocation of Iatan 2
ER-2010-0036	Supplemental Direct, Surrebuttal	Fuel Adjustment Clause
ER-2009-0090	Surrebuttal	Capacity Requirements
ER-2008-0318	Surrebuttal	Fuel Adjustment Clause
ER-2008-0093	Rebuttal, Surrebuttal	Fuel Adjustment Clause Low-Income Program
ER-2007-0004	Direct, Surrebuttal	Resource Planning
GR-2007-0003	Direct	Energy Efficiency Program Cost Recovery
ER-2007-0002	Direct	Demand-Side Program Cost Recovery
ER-2006-0315	Supplemental Direct, Rebuttal	Energy Forecast Demand-Side Programs Low-Income Programs
ER-2006-0314	Rebuttal	Jurisdictional Allocation Factor
EA-2006-0309	Rebuttal, Surrebuttal	Resource Planning
ER-2005-0436	Direct, Rebuttal, Surrebuttal	Low-Income Programs Energy Efficiency Programs Resource Planning
EO-2005-0329	Spontaneous	Demand-Side Programs Resource Planning

Missouri Public Service Commission Staff Case Listing (cont.)

EO-2005-0293	Spontaneous	Demand-Side Programs Resource Planning
ER-2004-0570	Direct, Rebuttal, Surrebuttal	Reliability Indices Energy Efficiency Programs Wind Research Program
EF-2003-0465	Rebuttal	Resource Planning
ER-2002-425	Direct	Derivation of Normal Weather
EC-2002-1	Direct, Rebuttal	Weather Normalization of Class Sales Weather Normalization of Net System
ER-2001-672	Direct, Rebuttal	Weather Normalization of Class Sales Weather Normalization of Net System
ER-2001-299	Direct	Weather Normalization of Class Sales Weather Normalization of Net System
EM-2000-369	Direct	Load Research
EM-2000-292	Direct	Load Research
EM-97-515	Direct	Normalization of Net System
ER-97-394, et. al.	Direct, Rebuttal, Surrebuttal	Weather Normalization of Class Sales Weather Normalization of Net System Energy Audit Tariff
EO-94-174	Direct	Weather Normalization of Class Sales Weather Normalization of Net System
ER-97-81	Direct	Weather Normalization of Class Sales Weather Normalization of Net System TES Tariff
ER-95-279	Direct	Normalization of Net System
ET-95-209	Rebuttal, Surrebuttal	New Construction Pilot Program
EO-94-199	Direct	Normalization of Net System
ER-94-163	Direct	Normalization of Net System
ER-93-37	Direct	Weather Normalization of Class Sales Weather Normalization of Net System
EO-91-74, et. al.	Direct	Weather Normalization of Class Sales Weather Normalization of Net System
EO-90-251	Rebuttal	Promotional Practices Variance
ER-90-138	Direct	Weather Normalization of Net System
ER-90-101	Direct, Rebuttal, Surrebuttal	Weather Normalization of Class Sales Weather Normalization of Net System
ER-85-128, et. al.	Direct	Demand-Side Update
ER-84-105	Direct	Demand-Side Update

Electric Utility Fuel Adjustment Clause in Missouri: History and Application Whitepaper

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Electric Utility Fuel Adjustment Clause in Missouri:
History and Application Whitepaper

Introduction

The purpose of this whitepaper is to provide a general description of the history of electric utility fuel adjustment clauses ("FACs") in Missouri prior to and after the passage of Section 386.266 Revised Missouri Statutes ("RSMo") in 2005[1] and provide an understanding of the functionality of the FACs currently implemented throughout the state of Missouri. This whitepaper is not an exhaustive description of the FAC in Missouri but is intended to provide a basic understanding of the history and application of Section 386.266 in a neutral and unbiased manner.

Recovery of Fuel and Purchased Power Costs Prior to Section 386.266 RSMo

In the 1979 Missouri Supreme Court opinion of *Utility Consumer Council of Missouri, Inc. v. P.S.C*,[2] the Court concluded FAC surcharges were unlawful because they allowed rates to go into effect without considering all relevant factors. The Court warned "to permit such a clause would lead to the erosion of the statutorily-mandated fixed rate system."[3] The Court further explained, "If the legislature wishes to approve automatic adjustment clauses, it can of course do so by amendment of the statutes and set up appropriate statutory checks, safeguards, and mechanisms for public participation."[4]

After this Supreme Court opinion, fuel and purchased power costs for Missouri investor-owned utilities were normalized and included in the determination of the utility's revenue requirement for general rate proceedings. This provided an incentive to the electric utility that, if it managed its activities in a manner that allowed it to reliably serve its customers at a cost lower than what was included in its revenue requirement in the last rate case, all the savings were retained by the electric utility. If costs were greater than the costs included in the revenue requirement, the electric utility absorbed the increased costs. When the electric utility believed that it could no longer absorb the increased costs, the electric utility would ask the Commission for an increase in its rates.

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[1] Section 386.266 RSMo was Truly Agreed To and Finally Passed by the Missouri House of Representatives and Senate on April 27, 2005. Governor Matt Blunt signed this legislation on July 14, 2005. http://www.senate.mo.gov/05info/BTS_Web/Actions.aspx?SessionType=R&BillID=5755

[2] State ex rel. Utility Consumers Council, Inc. v. P.S.C., 585 S.W.2d 41(MO. 1979)

[3] Id. at 57.

[4] Id.

This incentive worked well for the Missouri electric utilities and their customers for the next twenty-five years. The two largest investor-owned electric utilities, Union Electric Company ("Union Electric") and Kansas City Power & Light Company ("KCPL") went for a period of twenty years without a rate increase request due to the excess generation they built in the 1970's and 1980's. Capital costs of these plants were included in the customers' rates of these electric utilities. Excess generation and capacity from these utilities and other regional providers that over-built was sold through long-term contracts on a cost-plus basis to the smaller investor-owned electric utilities in the state. This resulted in minimal rate increase requests for these smaller investor-owned electric utilities and offset some of the capital costs paid by Union Electric Company and KCPL's customers. Eventually the large utilities' customers load requirements grew into the need for their own capacity and they did not renew the long-term contracts. Then, to meet their customers' needs, the smaller electric utilities began to build the least cost option - natural-gas fired generation plants. While these plants were inexpensive to build, the fuel cost was uncertain.

In the early 1990's, restructuring of the electric utilities began occurring in other parts of the nation. In the mid-1990's the Missouri Legislature considered restructuring Missouri's investor-owned electric utility companies. At the end of 2000, after two months of extraordinarily cold weather and continued reports of extreme storage withdrawals, the commodity price of natural gas spiked to nearly $10 per thousand cubic feet ("Mcf") in late December after remaining consistently between $1/Mcf to $3/Mcf since the inception of the unregulated wholesale natural gas markets in the 1980s.[5] These wildly fluctuating natural gas prices had little impact on the total fuel costs of KCPL and Union Electric since most of their customers' needs were met through nuclear and coal generation. However, the fluctuating natural gas prices significantly impacted the smaller electric utilities' fuel and purchased power costs.

Overview of Section 386.266 RSMo

The provisions of Section 386.266 RSMo, also known as Senate Bill 179 ("SB 179"), took effect on January 1, 2006.[6] This section gives the Missouri Public Service Commission ("Commission"), among other things, the authority to approve rate schedules authorizing periodic rate adjustments outside of general rate proceedings to reflect increases and decreases in its prudently incurred fuel and purchased power costs, including transportation costs. An FAC is a mechanism designed to reflect increases and decreases in fuel and purchased power costs, including transportation. The statute, in addition to requiring approval from the Commission for the implementation of an FAC, includes other provisions including some consumer protections.

[5] Missouri Public Service Commission EFIS Case No. GW2001398XXX, Item no. 44, Final Report of the Missouri Public Service Commission's Natural Gas Commodity Price Task Force, August 29, 2001

[6] §386.266.12.

It requires the Commission to approve, modify, or reject FACs only as a part of a general rate case proceeding in which all costs and relevant factors are considered. It allows the Commission to include in an FAC features designed to provide incentives to improve the efficiency and cost-effectiveness of the electric utility's fuel and purchased-power procurement activities. If the Commission approves an FAC, the electric utility with the FAC must file a general rate increase case with effective dates of new rates no later than four years after its approval. Prudence reviews of the costs included in an FAC are to be conducted at least every eighteen months and true-ups are required at least annually. Amounts charged/refunded to the customers through an FAC are required to be separately disclosed on each customer's bill.

Section 386.266.1, which is the provision that grants the Commission the authority to approve, reject or modify FACs, applies only to investor-owned electric utilities in Missouri. At the time it became effective, there were four investor-owned electric utilities in Missouri – Union Electric, KCPL, Aquila, Inc. ("Aquila"), and the Empire District Electric Company ("Empire"). Union Electric subsequently did business as AmerenUE and is now doing business as Ameren Missouri. Aquila is now doing business as KCP&L – Greater Missouri Operations Company ("GMO").

Development of Commission Rules Regarding FACs

Section 386.266.9 RSMo gives the Commission the authority to promulgate rules to govern the structure, content, and operation of FACs. The Commission is also given the authority to promulgate rules regarding the procedures for the submission, frequency, examination, hearing, and approval of FACs. Soon after Section 386.266 RSMo went into effect, the Staff of the Public Service Commission ("Staff") began the work of developing rules governing the implementation of this section. It was determined that there would be two rules: one rule, found in *Chapter 3 Filing and Reporting Requirements* of the Commission's rules as *4 CSR 240-3.161 Electric Utility Fuel and Purchased Power Cost Recovery Mechanisms Filing and Submission Requirements*, provides the filing and information requirements necessary for requesting approval, continuation, modification, and discontinuation of an FAC along with filing and submission requirements for changes to the FAC rates and true-ups. It also provides the contents of quarterly surveillance reports and monthly reporting requirement for electric utilities that are allowed an FAC. A second rule, *4 CSR 240-20.090 Electric Utility Fuel and Purchased Power Cost Recovery Mechanisms,* provides the structure and governance requirements for an FAC.

Staff worked diligently with a broad group of stakeholders - including representatives from electric utilities, large customers, AARP, and the Office of the Public Counsel ("OPC") in the development of proposed rules to present to the Commission. Auditors, engineers, economists, and attorneys worked together in over fifteen workshops collaborating to develop specific language to propose to the Commission rules to implement the provisions of Section

386.266 RSMo pertaining to FACs. The Commission opened Case No. EX-2006-0472 on June 15, 2006 with a finding of necessity for rules to establish and implement an FAC and began the formal rulemaking process with the proposed 4 CSR 240-3.161 and 4 CSR 240-20.090 rules developed through the collaborative workshop process. Public hearings regarding the proposed FAC rules were held in Kansas City, St. Louis, Overland, Cape Girardeau, Jefferson City and Joplin in late August 2006 and early September 2006. Written comments were received from seven individuals and fourteen groups or companies. The Commission issued its final orders of rulemaking on September 21, 2006.[7] The final order was published in the December 1, 2006 *Missouri Register* effective January 30, 2007.[8]

Key Provisions of the FAC Rules

Despite concerns that an FAC would contribute to over-earnings by electric utilities by the both the non-utility parties that participated in developing the proposed rules and those that provided comments in the formal rulemaking process, the resulting FAC rules do not contain an earnings test. In FAC proceedings, the Commission is only required to review the costs and revenues included in the FAC. Decreases in expenses and increases in revenues not included in the FAC are not considered by the Commission. However, utilities with an FAC are required by the Commission rules to submit quarterly surveillance reports to Staff, OPC, and other parties. These surveillance reports include rate base quantifications, capital quantifications and income statements for the electric utilities as a whole.[9] The information from these reports includes the earnings of the electric utility for the prior quarter and could be used in an over-earnings complaint case.[10]

Because the statute requires adjustments to FAC rates reflect increases and decreases in prudently incurred costs, the rules require that FAC recoveries be based on historical costs.[11] Therefore, before the electric utility can begin billing to recover FAC costs, the costs in the utility's FAC must be incurred and any revenues included in the FAC to offset those costs must be received. Interest at the utility's short-term debt rate is applied to the net of these costs and revenues and recovered or returned to the ratepayers through the FAC rate.

The rules are not prescriptive regarding the design of FAC rates. However, 4 CSR 240-20.090(9) does require that FAC rates reflect differences in losses incurred in the delivery of electricity at

[7] Missouri Public Service Commission, Case No. EX-2006-0472, EFIS items 27 and 28
[8] http://s1.sos.mo.gov/CMSImages/adrules/moreg/previous/2006/v31n23/v31n23b.pdf
[9] 4 CSR 240-3.161(6)
[10] However, the Commission, in case no. EC-2014-0223, stated that these surveillance reports alone do not provide a complete or accurate picture of earnings sufficient to reset the utility's rates.
[11] 4 CSR 240-20.090(2)(F)

different voltage levels for different rate classes based on system loss studies that must be conducted at least every four years.

While Section 386.266.1 allows the Commission to include features in an FAC designed to provide the electric utilities with incentives to improve the efficiency and cost-effectiveness of the utilities fuel and purchased-power procurement activities, the rules are not prescriptive regarding what such an incentive feature would look like. Instead it allows incentive features to be proposed in rate cases in which an electric utility requests the establishment, continuation or modification of an FAC.[12] Incentive features can be proposed for the Commission's consideration by any of the parties in rate cases in which the electric utility is proposing the establishment, continuation, or modification of an FAC.

Section 386.266 is silent regarding the inclusion in an FAC of any fuel related type of revenues. The Commission rules do not require the inclusion of fuel related revenues, such as off-system sales revenues,[13] in an FAC. The rules do require that if an FAC includes revenues from off-system sales, the FAC include prudently incurred fuel and purchased power costs associated with off-system sales.[14]

History of Requests for FACs

Empire was the first electric utility to request cost recovery of fuel costs under Section 386.266 RSMo when it filed Case No. ER-2006-0315 on February 1, 2006. This case was filed while the Commission rules were being drafted. In this case, Empire did not request an FAC. Instead it requested an Energy Cost Rider ("ECR") to recover costs between rate cases. Due to a stipulation Empire had entered into in a prior rate case, the Commission required Empire to remove from its pleadings and other filings its request and support for an ECR.[15] Prior to Empire's next rate case, Case No. ER-2008-0093 filed on October 1, 2007, the Commission rules had been finalized and were effective. The Commission granted Empire an FAC in its July 30, 2008, *Report and Order* in ER-2008-0093. The Commission has authorized continuation of an FAC with modifications in all general rate cases subsequently filed by Empire.

On July 3, 2006 two of Missouri's investor-owned electric utilities filed general rate increase cases in which they requested an FAC. Union Electric, then doing business as AmerenUE, requested the Commission grant it an FAC in Case No. ER-2007-0002 and Aquila requested an FAC in Case No. ER-2007-0004. While the FAC rules were not final at this time, the Commission had, just eighteen days earlier, sent proposed rules to the Missouri Office of the Secretary of

[12] 4 CSR 240-20.090(11)
[13] Off-system sales revenues are the revenues from sales of energy by the electric utility above what is needed by the utility's customers.
[14] 4 CSR 240-3.161(1)(A) and 4 CSR 240-20.090(1)(B)
[15] EFIS item 57, *Order Clarifying Continued Applicability of the Interim Energy Charge*, effective May 12, 2006.

State for publication in the Missouri Register. The Commission's determination of the final FAC rules occurred while these rate cases were pending.

In its May 22, 2007 *Report and Order* in the AmerenUE case ER-2007-0002, the Commission concluded:

> After carefully considering the evidence and arguments of the parties, and balancing the interests of ratepayers and shareholders, the Commission concludes that AmerenUE's fuel and purchased power costs are not volatile enough [to] justify the implementation of a fuel adjustment clause at this time.

AmerenUE filed another general rate increase case on April 4, 2008, again seeking the Commission's approval of an FAC in Case No. ER-2008-0318. In its January 27, 2009 *Report and Order*[16] in this case, the Commission authorized AmerenUE to implement an FAC. The Commission has authorized continuation of an FAC with modifications in all general rate cases subsequently filed by Union Electric now doing business as Ameren Missouri.

The Commission authorized the first FAC for a Missouri investor-owned electric utility under Section 386.266 RSMo in its May 17, 2007 *Report and Order* in Aquila's general rate proceeding in case ER-2007-0004. FAC base rates were approved for each of Aquila's two rate districts, then designated as Aquila Networks-MPS and Aquila Networks-L&P. The actual effective date of Aquila's FAC was delayed when the Commission found that the proposed FAC tariff sheets filed by Aquila were not consistent with its *Report and Order*. Tariff sheets implementing the FAC consistent with the Commission's *Report and Order* were approved on June 29, 2007 effective July 5, 2007. Following this rate case, Great Plains Energy acquired Aquila renamed it GMO. The Commission has authorized the continuation of an FAC with modifications in all general rate cases subsequently filed by GMO.

KCPL was the last Missouri electric utility to be granted an FAC. At the time that SB 179 was being debated at the Legislature, KCPL was negotiating a regulatory plan that would address financial considerations of KCPL's investment in Iatan 2 and other investments and the timeliness of the recovery of the costs of these investments. As a part of the *Stipulation and Agreement*[17] in that case, KCPL agreed, among other items, that prior to June 1, 2015, it would not seek to utilize any mechanism authorized in SB 179. Therefore, KCPL did not request an FAC until the general rate case ER-2014-0370 it filed on October 30, 2014. The Commission granted KCPL an FAC in its September 2, 2015 *Report and Order*.[18] Tariff sheets implementing an FAC for KCPL became effective September 29, 2015.

[16] EFIS item no. 589, page 70
[17] Case No. EO-2005-0329, EFIS item no. 1
[18] EFIS item no. 592, page 30

General Structure of FACs in Missouri

While there are some differences in the details of each electric utility's FAC, the general structure of the FACs of each of the electric utilities is the same. An estimate of the FAC costs and revenues, known as Net Base Energy Cost or NBEC, is identified and included in the base rates of each electric utility. The FAC rate is based on the difference between the FAC costs included in base rates and the actual FAC costs incurred. FAC costs are tracked in a designated accumulation period and the difference between actual FAC costs and NBEC is recovered or returned in a designated recovery period.

Even though the rule is not prescriptive regarding the design of the FAC rate, in practice, all of the electric utility's FAC rates are volumetric rates based on customer energy usage. A base factor is calculated in each general rate proceeding as the NBEC divided by the rate case normalized kilowatt-hours ("kWh"). The Commission's rule requires that the FAC is to be based on historical costs[19] so there cannot be an FAC rate until FAC costs are incurred. Therefore the initial FAC rate, ("FAR"), is set at zero when the Commission approves the establishment of an FAC for each of the electric utilities.

To derive a rate to be charged the customers after FAC costs have been incurred, the difference between the actual costs incurred (actual net energy cost or ANEC) and the costs already included in the base rates (NBEC), either positive or negative, is divided by the expected energy use of the utility's customers over the recovery period. Because rule requires voltage losses to be taken into account in the FAC, a FAR is calculated for each of the voltage levels that the utility provides service at based on loss factors derived in the last rate case. These loss-adjusted FARs are the rate used to bill the FAC to the customers.

Accumulation and Recovery Periods

An accumulation period is the time over which the electric utility tracks the ANEC. Commission rule allows up to four accumulation periods a year but requires at least one accumulation period a year. The Recovery Period is the time period over which the difference between the accumulation period ANEC and NBEC is billed to the utility's customers.

The accumulation periods and recovery periods for the electric utilities are shown in the table below.

[19] 4 CSR 240-20.090(2)(F)

Electric Utility	Accumulation Periods	Recovery Periods
Ameren Missouri	February through May	October through May
	June through September	February through September
	October through January	June through January
KCPL	January through June	October through September
	July through December	April through March
GMO	June through November	March through February
	December through May	September through August
Empire	September through February	June through November
	March through August	December through May

The recovery periods are twice as long as the accumulation periods for Ameren Missouri, KCPL, and GMO. The purpose of having recovery periods longer than the accumulation periods is to reduce the FAR and minimize the impact of the change in rates on the customers' bills. Ameren Missouri's accumulation periods are four months and the costs from the four month accumulation period are billed (recovered or returned) over eight months. The accumulation periods of KCPL and GMO are six months while the recovery periods are twelve months. Empire is the only utility where the recovery period is the same length as the accumulation period - both are six months.

The timing of recovery periods for Ameren Missouri, KCPL, and Empire were set to minimize the number of times during a year that changes in rates impact bills. The base rates for all of the electric utilities change twice a year. Base rates are higher in the summer months of June through September for all of the electric utilities because typically the cost to provide electricity is higher in these summer months. The lower, non-summer rates are billed in October through May.

The timing of the recovery periods of Ameren Missouri means that customers see both base rates and FAR changes in June and October and then see another rate change, due to the change in the FAR, in February. Without alignment of the timing of recovery periods, customers of Ameren Missouri could be impacted by changes in rates up to five times a year – twice in base rates and three times for the FAC rates.

Similarly, the timing of one of the FAC recovery periods for KCPL is October when base rates also change. One of Empire's recovery periods begins in the same month that the base rates change for summer resulting in rates changing for Empire's customers only three times a year.

The timing of FAC rate changes for KCPL and Empire results in their customers seeing changes in rates just three times a year instead of four.

Calculation of Fuel Adjustment Rates

At the end of the accumulation period, a NBEC is calculated for the accumulation period based on the Base Rate set in the rate case and the actual energy consumed by the electric utility's customers in the accumulation period. This NBEC is compared to the Actual Net Energy Costs (ANEC) incurred during that accumulation period. The FAR for the accumulation period is then calculated based on the difference between the actual historical costs incurred (ANEC) and the FAC costs billed in the base rates (NBEC) divided by the expected usage of the utility's customers over the recovery period and then adjusting the rate for delivery losses.

This is the FAR that the customer is billed for Empire since the recovery period is the same length as the accumulation period. For the other three electric utilities that have recovery periods that are twice as long as the accumulation periods, the FAR that is billed the customer is actually the sum of the loss adjusted FARs for two consecutive accumulation periods.

Price Signal Resulting From FACs

There is a common misconception that FACs provide customers more accurate price signals than the base rates. There are several reasons Missouri's FAC does not provide accurate price signals to customers. An accurate price signal is timing. Missouri's FAC is based on historical costs so customers are not billed the difference in the FAC costs until months after the costs are incurred. For example, fuel costs incurred in January for KCPL are not billed to its customers until the recovery period that begins in October. At the time that a change in fuel costs is seen on the customers' bills, it may no longer be an accurate representation of the fuel cost the utility is experiencing at that time.

Another reason that FACs in Missouri do not provide accurate price signals is that the accumulation periods bill costs or return savings to customers aggregated over several months. Increases in FAC costs in one month may be offset by decreases in FAC costs in the next month. In addition, the accumulation periods cross seasons of the year when FAC costs typically vary because the load requirements of the customers vary. For these reasons, the length of the accumulation period mutes any price signal.

Long recovery periods designed to reduce FAC rate volatility to customers also mutes the price signal to customers. For example, for KCPL any increase in costs in January is recovered over the time period of October of that same year through September of the next year. An increase in January is spread out over the twelve months of the recovery period so an increase in January combined with changes for all the months in the accumulation period and then spread over twelve months of estimated usage. This is the price signal that the customer is reacting to – not the actual increase in costs in January. In addition, the customer would not even be billed for the increase in costs in January until the October billing month. If FAC costs are volatile, the customer may be reacting to an increase in cost in the previous year during a time period when costs are actually decreasing. In this case, the FAC is sending the wrong price signal to the customer.

For these reasons the design and application of FACs in Missouri do not send accurate price signals to customers.

True-Up of FACs

SB 179 requires that true-ups of FACs occur at least annually.[20] The purpose of a true-up is to make sure that the electric utility recovers all the costs that it is entitled or all amounts due to the customers are refunded. Section 386.266 requires the true-up amount include interest at the electric utility's short-term interest rate.

In practice, true-ups occur after the end of each recovery period. Because KCPL, GMO, and Empire have two recovery periods a year, there are two FAC true-ups a year for these electric utilities. There are three FAC true-ups a year for Ameren Missouri since it has three recovery periods a year. A true-up is simply a comparison of the actual FAC billed the customers in the recovery period to the difference between the actual FAC costs and NBEC in the corresponding accumulation period. This difference, either negative or positive, is added as a true-up amount, including interest, to the FAC costs to be billed in the next recovery period.

The true-up amount is keyed off of the FAC billed not the FAC revenues recovered. This is to reduce complexity of how to deal with under-paid bills. While the FAC amount is separately identified on the customer's bill, the customer that only pays a portion of their bill does not designate what portion of the bill they are paying. The unpaid portion of the bill is included treated uncollectible. The rate case treatment for uncollectibles is determined in the rate case and is not dealt with in the FAC.

Prudence Reviews

[20] Section 386.266.4(2)

Section 386.266.4(4) requires prudence reviews of the costs in the FAC to occur at least every eighteen (18) months. Since the first FAC under section 386.266 was approved for GMO, the first prudence audit was conducted on GMO's FAC, followed by prudence audits on Empire and Ameren Missouri's FACs.[21] In Ameren Missouri's first prudence audit case, EO-2010-0255, the Commission determined that Ameren Missouri "acted imprudently, improperly and unlawfully when it excluded revenues" derived from power sales agreements from its FAC.[22] Because these power sales agreements crossed over two prudence review time periods, the Commission, in Ameren Missouri's second prudence audit, EO-2012-0074, made the same finding.[23] Since then Staff has only recommended one other imprudence finding in an FAC prudence audit. In case no. EO-2011-0390, the third GMO FAC prudence audit case, Staff alleged that GMO had acted imprudently in association with its hedging future purchases of spot market power by buying options to purchase natural gas. The Commission, in its *Report and Order* in this case, found that Staff failed to produce substantial controverting evidence demonstrating serious doubt to rebut the presumption of prudence with regard to GMO's hedging policy.[24]

There have been no other recommendations by the Staff regarding imprudence with respect to the FAC since the September 4, 2012, *Report and Order* in the third GMO FAC prudence audit case.

Incentive Mechanism

SB 179 allows the Commission to include, in an FAC, incentives to improve the efficiency and cost-effectiveness of the electric utilities' fuel and purchased power procurement.[25] The Commission, for each of the electric utilities, found that allowing the utility to have one hundred percent recovery of its FAC costs through an FAC would act as a disincentive for the utility to control FAC costs. The Commission determined that recovering a share of the difference between the NBEC and ANEC allows the electric utility a sufficient opportunity to earn a fair return on equity while protecting customers by providing an incentive to control costs. At the time that this white paper was written, the Commission had set that sharing percentage, for all of the electric utilities, to be 95%/5% - 95% of any increase in FAC costs above NBEC would be billed to the customers and the electric utility absorbs 5% while 95% of a

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[21] Case Nos. EO-2009-0115, EO-2010-0084 and EO-2010-0255 for GMO, Empire and Ameren Missouri respectively.
[22] *Report and Order,* page 2
[23] *Report and Order,* page 2
[24] Page 47
[25] Section 386.266.1

decrease in FAC costs below NBEC would be credited to customers and the electric utility retains 5% of the decrease.[26]

Given this incentive mechanism, the amount to be billed through the FAC is 95% of the difference between the ANEC and the NBEC. The result of this incentive mechanism is that, when costs are above the amounts included in base rates, the electric utility recovers almost 100% of the FAC costs. If FAC costs are below the amounts included in base rates, the utility recovers greater than 100% of its FAC costs. The table below shows examples of what occurs when actual costs are greater, equal to, and less than what is in the NBEC.

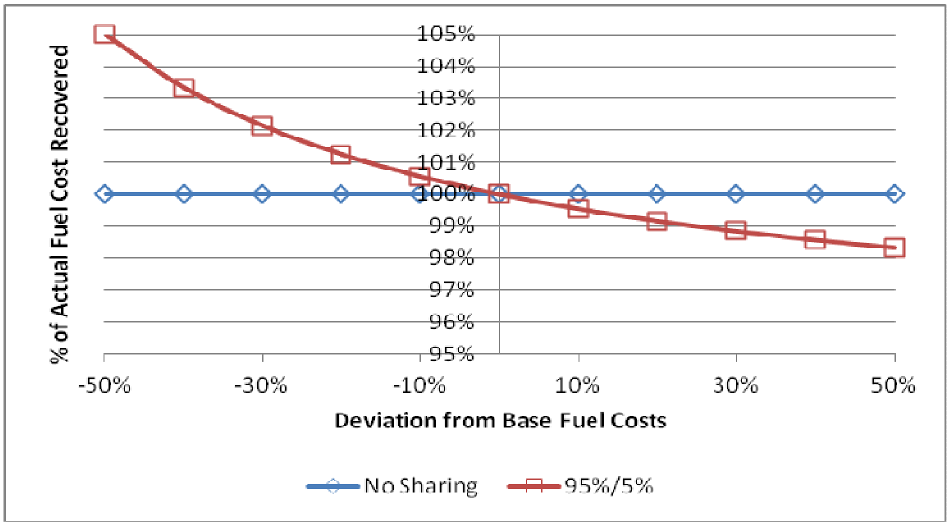
Impact of 95%/5% Sharing Mechanism

NBEC	ANEC	Diff	FAC Amt Billed to Customers	Amt Absorbed/ (Retained) by Company	Total billed to Customers	% FAC Costs Billed
$100	$150	$50	$47.50	$2.50	$147.50	98.3%
$100	$110	$10	$9.50	$0.50	$109.50	99.5%
$100	$100	$0	$0	$0	$100.00	100.0%
$100	$90	($10)	($9.50)	($0.50)	$90.50	100.6%
$100	$50	($50)	($47.50)	($2.50)	$52.50	105%

This table shows incentive mechanism allows the utility to bill its customers for 98.3% of its FAC costs when its ANEC is 50% higher than what is included in base rates, i.e., even if the actual FAC costs incurred are 50% higher than what was included in the base rates, the electric utility recovers 98.3% of its actual FAC costs.[27] Likewise, if actual fuel costs are 50% lower than what is included in base rates, the utility will recover 105% of its actual FAC costs. If the utility manages to reduce its actual FAC costs any amount below NBEC, will recover more 100% of its FAC costs. This relationship is shown in the graph below.

[26] While parties in rate cases have proposed different sharing percentages and/or different incentive mechanisms, the only incentive mechanism implemented has been a 95%/5% sharing of the difference between ANEC and NBEC.

[27] For a utility to bill only 95% of its actual costs, the actual FAC costs would need to be over 1,000 times greater than the costs included in base rates



These relationships hold true regardless of the magnitude of the NBEC.

Importance of Correct NBEC

Because Missouri's FAC is based on the difference between a subset of normalized costs and revenues set in a rate case and actual costs and revenues, it is important the costs and revenues included in the NBEC of the FAC are the same as the costs and revenues included in base rates. The table below shows three different scenarios. To simplify the example, in these scenarios there is no sharing of the difference between ANEC and NBEC. All of the difference between the ANEC and NBEC is billed or returned to the customers.

Net Base Energy Cost (NBEC)	FAC Costs in Base Rates	Actual Net Energy Cost (ANEC)	Billed FAC Costs	Total FAC Costs Billed	Total billed as % of ANEC
Scenario 1 - NBEC Equal FAC Costs in Rates					
$100.00	$100.00	$110.00	$10.00	$110.00	100.00%
$100.00	$100.00	$100.00	$0.00	$100.00	100.00%
$100.00	$100.00	$90.00	-$10.00	$90.00	100.00%
Scenario 2 - NBEC Lower than FAC Costs in Rates					
$100.00	$110.00	$110.00	$10.00	$120.00	109.09%
$100.00	$110.00	$100.00	$0.00	$110.00	110.00%
$100.00	$110.00	$90.00	-$10.00	$100.00	111.11%
Scenario 3 - NBEC Higher than FAC Costs in Rates					
$100.00	$90.00	$110.00	$10.00	$100.00	90.91%
$100.00	$90.00	$100.00	$0.00	$90.00	90.00%
$100.00	$90.00	$90.00	-$10.00	$80.00	88.89%

The first scenario is a correct treatment of NBEC and FAC costs in Rates. NBEC is equal to the FAC costs included in base rates. In this scenario, when ANEC is higher than NBEC, the total FAC costs billed the customer is the $100 billed in the base rates and $10 billed through the FAC for a total of $110. When the ANEC is the same as the NBEC, the customers are billed nothing through the FAC and the utility recovers all of its FAC costs through its base rates. Lastly, when the actual costs are less than the NBEC, the customers' bills are reduced and the utility recovers all of its actual fuel costs.

In Scenario 2, the NBEC designated in the FAC is less than the FAC costs in rates. In this scenario, the customers always pay more than intended. Even when ANEC is the same as the FAC costs included in rates, the customer pays for the difference between the ANEC and NBEC. In this scenario, the customers always paying more than the actual FAC costs because the fuel costs included in the base rates is greater than the costs used to calculate the NBEC.

In Scenario 3, the NBEC is set higher than the FAC costs included in rates. In this scenario, the electric utility does not collect the actual energy costs because the amount of FAC costs included in rates is less than the NBEC set in the FAC. The amount recovered is the lower FAC costs included in rates and the difference between the higher NBEC and ANEC. In this scenario, the company does not receive the revenues that are intended with an FAC.

These scenarios show the importance of insuring that the FAC costs included in base rates are the same as the FAC NBEC. If they are not set correctly, either the customers overpay or the company is not afforded the opportunity to recover its costs as intended.

Future Application of the FAC

The FAC rules have a requirement that the Commission review the effectiveness of the rules by no later than December 31, 2010. On November 12, 2010, the Commission opened a repository file, EW-2011-0139,[28] as a repository file for documents and comments regarding effectiveness of the FAC rules. The electric utilities, OPC and other interested parties filed comments regarding the need for revisions to the rules by March 1, 2011. The Commission issued an order on March 27, 2014 directing staff to file a status report on the revision of the rules. Beginning on April 27, 2015, Staff began hosting a series of three workshops for stakeholders to provide input to Staff on its review of the rules and, where possible, prepare collaborative revisions to the rules. On February 4, 2015, the Commission directed Staff to complete its review and file its recommendations regarding changes to the rules by September

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[28] EW-2011-0139, *In The Matter Of A Repository File Concerning Staff's Review Of The Commission's Fuel Adjustment Clause Rules*

15, 2015. The Commission later extended that completion date to November 20, 2015 and then to February 15, 2016. At the time that this whitepaper was updated, the Commission had sent its proposed rule to the Department of Economic Development for review prior to it being sent to the Secretary of State to be published in the Missouri Register for comments.

GMO Requested FAC Costs and Revenues
Direct Testimony of Tim M. Rush
Schedule TMR-1

Expenses

General Leg Acct/ Resource Code	"Complete Explanation" Provided by GMO
501000/6000	NL Bit Coal and Freight Costs (Variable)
501000/6005	NL PRB Coal and Freight Costs (Variable)
501000/6030	NL Tire Costs (Variable)
501000/6001	NL Bit Coal Inventory Adj.
501000/6006	NL PRB Coal Inventory Adj.
501000/6035	NL Biofuels
501020	NL Coal and Freight Costs (Variable)
501000/6002	NL Bit Coal Freeze & Dust Treatment
501000/6007	NL PRB Coal Freeze & Dust Treatment
501030	SFR Coal & Freight Costs
501000/6016	NL Oil Costs
501000/6018	NL Oil Inventory Adj.
501000/6020	NL Gas
501000/6021	NL Gas
501000/6022	NL Gas
501000/6023	NL Gas
501000/6024	NL Gas
501000/6026	Hedge Settlements
501000/6027	NL Gas Adjustments
501000/6017	NL Propane
501000	Unit Train (Rail) Lease
501300	NL Additives
501400	NL Residuals Costs
501420	NL Residuals Costs
501450	NL Residuals Costs
504100	Contra-Steam Coal, Gas, Oil
509000	Emission Allowances
547000/6016	NL Oil
547000/6020	NL Gas Costs & Transportation (Variable)
547000/6021	NL Gas Costs & Transportation (Variable)
547000/6022	NL Gas Costs & Transportation (Variable)
547000/6023	NL Gas Costs & Transportation (Variable)
547000/6024	NL Gas Costs & Transportation (Variable)
547000/6027	NL Gas Adjustments
547000/6018	NL Oil Adjustments
547000/6026	Hedge Settlements
547000/6035	NL Biofuels
547020	NL Gas Costs & Transportation (Variable)
547030	SFR Gas Costs & Transportation (Variable)
555000	NL Purchased Power-Energy
555021	NL Purchased Power-Energy
555005	Purchased Power-Capacity (Short-term ONLY)

555030	SFR Purchased Power-Energy
555031	SFR Purchased Power-Energy
555035	SFR Purchased Power – WAPA
561400	Trans OP LD Dispatch Control & Dispatch
561800	Trans OP LD Dispatch Reliability Planning RTO
565000	Trans OP Trans of Elec by Others
565020	Trans OP Trans Res Load CHG
565027	Trans OP Trans by Other Demand
565030	SFR Transmission
575700	Trans OP MKT MON&COMP SER RTO
928000/Dept 415	Regulatory Commission Expense (FERC assessments)

Revenues

General Leg Acct	"Complete Explanation" Provided by GMO
447002	Bulk Power Sales
447012	Wholesale Sales Capacity (Short-term ONLY)
447030	SFR Off-system Sales
447035	SFR Off System Sales – WAPA
456009	Other Rev Transmission
456100	Revenue Trans Elec for Others
456109	Other Elec Rev Transmission

PRUDENCE REVIEW OF COSTS
RELATED TO THE FUEL ADJUSTMENT CLAUSE
FOR THE ELECTRIC OPERATIONS
OF
KCP&L GREATER MISSOURI OPERATIONS COMPANY

December 1, 2013 through May 31, 2015

MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

FILE NO. EO-2016-0053

Jefferson City, Missouri
February 29, 2016

****Denotes Highly Confidential Information****

Appendix A

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Schedule LM-D-4
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Schedule LMM-1

History of Staff's Position Regarding

GMO's Capacity Additions Since 2000

In 2000, Aquila, Inc. ("Aquila") entered into a five-year purchased power agreement ("PPA") to obtain capacity and energy from the exempt wholesale generator Aries Plant owned by Aquila Merchant and Calpine. At the time when Aquila was planning to replace the power and energy provided through this agreement, Aquila met with Staff and the Office of the Public Counsel twice a year to update them on Aquila's resource needs and plans to meet those needs. The only information given to Staff at those meetings was Aquila's presentation material. Staff provided feedback based on the presentation materials and statements made during the presentations. Staff did not do a formal or informal review of the resource plan updates presented at the meetings. Sometimes, if Staff felt that it was warranted, Staff would respond to Aquila after a meeting by a letter expressing its concerns.

Aquila issued a Request For Proposals ("RFP") in the spring of 2001 for capacity for the delivery of energy in June 2005. The proposals Aquila received included purchased power offers respecting merchant coal, combustion turbine ("CT") and combined cycle ("CC") plants. However, the electric industry changed considerably when Aquila was reviewing the proposals in 2002, so at the urging of Staff, Aquila reissued the RFP in early 2003. At the June 26, 2003 resource planning update meeting with Staff and Office of Public Counsel, Aquila presented the results of its analysis of the bids it received from this second RFP. Included in the responses were proposals for wind, coal, CTs, and CCs. All of the proposals except one were purchased power agreements. Aquila reviewed the bids and then contacted neighboring utilities to see what other supply options might be available. All of the proposals, including available capacity that Aquila learned of from talking with neighboring utilities, were evaluated against the option of Aquila building a CT/CC plant.

At this June 26, 2003 meeting, Aquila told Staff that an "undisclosed" bidder had offered it an excellent bid for 600 MW, but Aquila could not tell Staff much about the bid at that time. Because this would be more than enough to cover its needs, Aquila felt that no other capacity was needed. Staff filed rebuttal testimony on September 10, 2003 in EF-2003-0465 stating its concerns regarding Aquila's need to replace the Aries contract. Staff learned in a data request response from Aquila in this case that this bid withdrawn and a substitute proposal was not offered to Aquila.

On January 27, 2004, Aquila again met with Staff, this time not in a resource planning meeting, but in a meeting to let Staff know about Aquila's power supply acquisition process for the next five years. In this meeting, Aquila's preferred/proposed resource plan over the short term was to build three combustion turbines and to enter into three-to-five year PPAs based off of the bids to the 2003 RFP. Staff was concerned regarding the short-term nature of Aquila's preferred/proposed plan, so three days later on January 30, 2004, Staff responded with a letter to Mr. Dennis Williams of Aquila in which Staff, expressed its concern regarding Aquila's short-sightedness. Staff also explained in the letter that it was Staff's belief that Aquila needed to be looking at base-load generation because Aquila should not become overly dependent upon short-term PPAs.

Aquila met with Staff on February 9, 2004 to provide its semi-annual resource update. This update, which took into consideration events over a twenty-year time horizon, showed that Aquila's least cost plan was to build five 105 MW CTs in 2005 and to purchase a small amount of capacity on the market in 2005. Then, between 2005 and 2009, Aquila would meet its growth through purchases on the market; build a CT in 2009 and another in 2010. It also called for Aquila to pursue base load capacity for 2010. Aquila's preferred plan differed from the least cost plan only in that instead of building five 105 MW CTs in 2005, Aquila would build three 105 MW CTs in 2005 and enter into a 200 MW PPA in 2005.

At the next semi-annual update on July 9, 2004, Aquila still showed that the five 105 MW CTs plan was least cost; however the three 105 MW CTs with PPAs was still its preferred plan. Aquila had found a very good 75 MW PPA with Nebraska Public Power District ("NPPD"), but it was still pursuing the other PPAs upon which it had received bids. At subsequent resource planning update meetings Aquila provided updates on the three 105 MW CTs and Aquila's pursuit of PPAs. Other than the 75 MW PPA with NPPD, Aquila was unable to enter into a PPA of more than a few months duration.

Aquila followed its preferred plan by building three 105 MW CTs at its South Harper site near the City of Peculiar and entering into a short-term purchased-power contract for power {capacity and/or energy} from another plant owned by Aquila Merchant - the 300 MW Crossroads plant in Mississippi - to meet its capacity needs for 2005.

In Aquila's first general electric rate increase case after the expiration of the Aries PPA, Case No. ER-2005-0436, Staff asserted that, given the information available to

Aquila from its resource planning process when Aquila decided how it would replace the power it was obtaining through the Aries capacity contract, Aquila should have built five 105 MW CTs. In that case, it was Staff's position that utilities should carefully do risk and contingency analysis of their resource plans and chose a resource plan that is robust across many scenarios of possible future events. That is still Staff's position. Prudently building and owning generation, whether it is base load, intermediate or peaking, provides price stability for Missouri consumers. PPAs are useful tools and are typically less expensive than building generation in the short-term, but they should not be relied upon as long-term solutions to capacity needs in the planning process without a firm long-term contract in hand. It was Staff position that, instead of relying on short-term PPAs, Aquila should have had five 105 MW CTs built by 2005 and that it then would have had that capacity available to serve its customers for the next thirty years.

This was the first case, Case No. ER-2005-0436, where, in lieu of costs based on Aquila's three 105 MW CTs South Harper power plant and a purchased power agreement, Staff included the costs of a new site with five installed 105 MW CTs in its case to approximate a self-build option for MPS. At that time there was ongoing litigation involving the South Harper power plant, so Aquila was again using short-term purchased power contracts to meet its capacity needs. The parties in Case No. ER-2005-0436 entered into a Stipulation and Agreement regarding fuel and purchased power expenses. The Stipulation and Agreement was silent regarding how Aquila should meet its capacity requirements.

In Aquila's next rate increase case, Case No. ER-2007-0004, Aquila was still relying on the three 105 MW CTs at South Harper and short-term PPA. Due to Aquila's continued litigation regarding the South Harper power plant, in this case Staff took the position that Aquila should have built five 105 MW CTs in 2005 to meet its capacity and energy needs, which was consistent with Staff's position in Aquila's preceding rate case. In this case Staff and other parties entered into another Stipulation and Agreement regarding fuel and purchased power expenses that was silent on how Aquila should meet its capacity requirements.

Staff's position remained that Aquila should have built five 105 MW CTs early enough to meet its capacity needs in 2005. In 2008, Section 393.171 RSMo. was passed which allowed the Commission to grant Aquila a certificate of convenience and necessity ("CCN") for South Harper and the substation associated with it. The Commission granted Aquila a CCN for South Harper and the substation effective March 28, 2009 in Case No. EA-2009-0118.

Aquila obtained this CCN during the pendency its next rate increase case (Case No. ER-2009-0090). By that time Great Plains Energy had acquired Aquila and had renamed it KCP&L – Greater Missouri Operations Company ("GMO"). Once the legal issues surrounding South Harper were resolved and the Commission had granted Aquila a CCN for South Harper, Staff's position changed and Staff included the capacity and running costs of the three 105 MW CTs at South Harper in its cost of service determination for GMO, but Staff maintained its position that Aquila should have built five 105 CTs in 2005, not three. Again, in Case No. ER-2009-0090, Staff and other parties entered into another Non-Unanimous Stipulation and Agreement regarding fuel and purchased power expense which was silent on how GMO should meet its capacity requirements.

As a part of this Non-Unanimous Stipulation and Agreement filed on May 22, 2009 in Case No. ER-2009-0090, GMO did agree to provide an analysis to be conducted by GMO regarding the Crossroads units and capacity additions for the Company. GMO provided this analysis to Staff and parties on May 31, 2010. This study was based on adding capacity at 2009 costs and included the generic CTs at 2009 costs. However, the time GMO needed capacity was the summer peak season of 2005, at the same time as when the Aries PPA expired. Aquila's least cost plan was to build five CTs instead of the three Aquila built at South Harper to be in service during summer of 2005. So GMO's analysis provided to Staff on May 31, 2010, was not useful for determining the prudency of Aquila's actions in 2005.

Staff Expert: Lena M. Mantle